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PRELIMINARY EMISSIONS ASSESSMENT OF CONVENTIONAL STATIONARY COMBUSTION SYSTEMS. VOLUME I. EXECUTIVE SUMMARY

Norman Surprenant, et al

GCA Corporation

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VOLUME I--EXECUTIVE SUMMARY

by

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ABSTRACT

This document is an executive summary of a preliminary emissions assessment of the air, water, and solid waste pollutants produced by conventional stationary combustion systems. Results are summarized for the following four principal categories of such systems: Utilities - electric generation; Industrial - steam generation, space heating and stationary engines; Commercial/Institutional - space heating and stationary engines; and Residential - space heating. Process types and operating efficiencies, fuel consumption, pollutant sources and characteristics, major research and development trends, fuel consumption trends, and technical areas where emission data are incomplete are summarized for each principal combustion system category. A uniform combustion source classification system was developed and the pollutant emissions from applicable unit operations are summarized for each of 56 source classifications.

This report was submitted in fulfillment of Contract 68-02-1316, Task Order No. 11, by the GCA/Technology Division under the sponsorship of the Environmental Protection Agency. Work was completed as of 7 November 1975.

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SECTION I

INTRODUCTION AND SUMMARY

PROGRAM OVERVIEW

The emission of pollutants to air and water and the generation of solid waste by conventional stationary combustion systems were assessed in this program. The assessment was confined to emissions resulting from operations and processes at the combustion site and did not include remote effects such as those arising from mining and transportation.

Four principal categories of conventional stationary combustion systems were considered:

- Utilities - electric generation
- Industrial - steam generation, space heating, and stationary engines (direct heating and chemical conversion were excluded)
- Commercial/Institutional - space heating and stationary engines
- Residential - space heating

The principal combustion categories were further divided into subcategories according to a classification scheme based on fuel type, combustion unit type, firing technique, thermal rate, fly ash reinjection and application of control measures or devices. A total of 56 of the combustion system subcategories were selected for emphasis in the contract investigations. These systems were chosen for study because preliminary analyses indicated they were the largest systems included in the classification system.

Emission estimates for these selected systems were calculated and presented, on a unit operations basis, in a series of emission summary tables. The data presented in the emission summary tables deal with national averages or ranges based on the best available information. While national figures cannot be related to individual plants, they do indicate the relative importance of various emission streams.

The major unit operations or processes that were utilized as the basis for summarizing air and water emissions and solid waste were:

- Flue gas emissions
- Ash handling
- Cooling systems
- Water treatment
- Fuel handling
- Flue gas desulfurization

The major pollutants for which emission estimates were derived were:

- Air:
  - Particulates
  - Sulfur oxides (SO_x)
  - Nitrogen oxides (NO_x)
  - Hydrocarbons (HC)
  - Carbon monoxide (CO)
  - Trace elements (28 elements)
  - Benzene soluble organics (BSO)*
  - Particulate polycyclic organic matter (PPOM)
    - Benzo(a)pyrenes (BaP)
  - Polyhalogenated hydrocarbons (PHH)
    - Polychlorinated biphenyls (PCB)
    - Polybrominated biphenyls (PBB)
  - Radioactive elements
- Water:
  - Total solids (TS)
  - Suspended solids (TSS)
  - Dissolved solids (TDS)
  - pH
  - Trace elements

*A list of acronyms used in this report is provided in Appendix B.

- Solid: Bottom ash
  Fly ash
  Desulfurization solids
  Trace elements

The emission estimates presented in the emission summary tables were based on a survey of data existing in the literature and information supplied through contact with members of industrial, governmental, and academic laboratories. A major use of these estimates will be to develop a preliminary priority ranking of the selected combustion systems based on the total emissions of these systems for the pollutants noted above.* To assist in the development of the priority ranking, fuel consumption and composition data, by state and/or region, and by the four principal combustion categories, were developed.

In addition to providing estimates of emissions from conventional stationary combustion sources, the contract effort involved development of the following data:

- State-of-the-art developments in combustion technology with respect to efficiency and pollutant generation.
- The number, type, location and size of the combustion systems within the United States based upon the selected combustion classification system.
- Trends in fuel consumption and boiler design and their impact on emissions.
- The extent and quality of available emission data.
- Identification of the major gaps in available pollutant data with respect to: types of combustion systems, unit operations within combustion systems, fuel composition and other parameters which can affect the composition and quantity of pollutant emissions.

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*This priority ranking activity is being conducted for the EPA, Industrial Environmental Research Laboratory, by Monsanto Research Corporation, Dayton, Ohio, under Contract 68-02-1404, Task Order No. 18.

- Identification of current and planned activities associated with emissions from conventional stationary combustion sources.

These data were deemed to be essential for a comprehensive assessment of the environmental impact of conventional combustion systems. Although the work described in this report is only a first step toward obtaining the information necessary for such an overall assessment, it enumerates the major gaps in the data base and allows decisions to be made concerning the additional work required to fill the data base gaps.

EMISSION SUMMARIES

The following discussion summarizes the contribution of the combustion sources to total national emissions and also provides an overview of the relative contributions of each of the four principal combustion system categories.

Fuel consumption by the principal categories of combustion sources is shown in Table 1. Coal was estimated to account for 26 percent of the combustion released energy generated, but produced 90 percent of the particulate, 75 percent of the SO_x, 50 percent of the NO_x, and approximately 80 percent of most trace elements emitted to the atmosphere by the combustion systems conducted in this study.* Coal furnished 55 percent of the energy used by the combustion-based electric utilities, 10 percent of the industrial stationary combustion energy, and only 3 percent and 2 percent of the combustion released energy used in commercial and residential sources, respectively. Natural gas was the primary fuel (greater than 65 percent of the total) in both the industrial and residential sectors. Gas represented 47 percent of the fuel used, and the only major air pollutant produced from this fuel was NO_x, representing 27 percent of the total.

Major emissions to air and water and solid waste generated by the four principal categories are presented in Table 2. Total emissions are

*Volume II of this report presents the data supporting these estimates.

Table 1. FUEL CONSUMPTION, CONVENTIONAL STATIONARY COMBUSTION SYSTEMS (10^{12} Btu/year)[a]

	Utilities (1974)	Industrial (1973)	Commercial (1973)	Residential (1973)	Total
External combustion	14,798	8,540	4,450[d]	8,057[e]	35,845
Coal	8,502	1,370	156	192	10,220
Bituminous	8,264	1,320	101	115	9,800
Anthracite	38	10	55	75	178
Lignite	200	40	-	2	242
Petroleum	3,039	1,700	2,379	2,280	9,398
Residual	2,901	1,270	1,269	0	5,440
Distillate	138	430	1,110	2,280	3,958
Natural gas	3,257	5,200	1,914	5,450	15,821
Internal combustion	589	2,760	50	0	3,399
Distillate oil	312	360	25	0	692
Natural gas	277	2,400	25	0	2,702
Total	15,387[b]	11,300[c]	4,500[d]	8,057[e]	39,244

[a]Although it is EPA's policy to use the metric system for quantitative descriptions, the British system is used in this report because the data were originally reported in British units. Readers who are more accustomed to metric units may use the table of conversions, Appendix A.

[b]Solid Refuse fuel provided < 0.005 percent of this total.

[c]Includes 20 x 10^{12} Btu of bagasse and 250 x 10^{12} Btu of wood as fuel.

[d]Includes 1 x 10^{12} Btu of wood as fuel.

[e]Includes 135 x 10^{12} Btu of wood as fuel.

Table 2. MAJOR EMISSIONS FROM CONVENTIONAL STATIONARY COMBUSTION SYSTEMS

	Air								Water			Solid waste		
						Organics[a]								
	Particulates, %	SO_x, %	NO_x, %	HC, %	CO, %	BSO, %	PPOM, %	BaP, %	Total solids, %	Dissolved solids, %	Waste heat, %	Total ash, %	Fly ash, %	Desulfurization solids, %
Electric Generation	63.8	72.5	64.8	34.0	33.6	8.8	0.3	0.2	94	94	80	87	94	94
Industrial	28.3	14.5	24.7	22.3	14.9	20.0	0.5	1.3	6	6	20	10	6	6
Commercial/ Institutional	4.9	6.7	7.3	12.2	7.7	16.0	0.2	0.4	< 1	< 1	< 1	1	< 1	0
Residential	3.0	6.3	3.2	31.5	44.7	55.2	99.0	98.1	NIL	NIL	NIL	2	0	0
Total, 10^3 ton/yr	7,060	22,100	10,950	353	1,070	125	4.14	0.40	5,000	3,700	7.9×10^{15} Btu/yr	54,000	36,000	3,500

[a]BSO = Benzene soluble organics
PPOM = Particulate polycyclic organic material
BaP = Benzo(a)pyrene
Does not include emissions of polyhalogenated biphenyls.
Total estimated emissions of polychlorinated biphenyls based on a single emission measurement is ~10 tons per year from coal-fired utility boilers.

presented along with the percentage contribution of the principal categories. Electric generation appears as the principal source of air pollutants from conventional stationary combustion systems other than carbon monoxide and organics. The major source of these two pollutants is residential combustion, suggesting that residential units burn fuel incompletely, and that efforts to improve the combustion efficiency of those myriad small sources are needed. Although representing only 2 percent of the fuel consumed by residential sources, coal is the major source of these emissions.

Emissions of polycyclic organic matter and polyhalogenated biphenyls (PHB) have not been extensively measured. POM emissions, on the basis of limited testing, are largely due to incomplete combustion, and as a result, are attributable principally to low efficiency residential heating units. Only one reference reported data for emissions of polychlorinated biphenyls (PCB) from combustion.[1] The average emission rate from a 125 MW pulverized coal-fired boiler was 0.8 mg/10^6 Btu. Assuming the same emission rate for all coal-fired boilers, the total PCB emission from coal would be 7.5 tons/yr. No data were found for emissions of PBB from coal and no data was found for any PHH emissions from oil or gas. Because of the known toxicity of these compounds, and their persistence in the environment, further work is necessary to identify the contribution of all combustion sources to existing levels in the environment.

The largest contributions to the burden of suspended and dissolved solids discharged to water (approximately 5 million tons/year from all stationary combustion sources) result from water used for coal ash handling. Ash handling wastewater discharge contains an estimated 2,300,000 tons of solids, largely in dissolved form. Waste water from boiler feedwater treatment is also a significant contributor from the utility sector because of stringent boiler water quality requirements. Over 90 percent of the water pollutants resulting from stationary combustion are attributable to electric

utilities. Coal ash constitutes the major solid waste material with ash production at approximately 54 million tons/year and with electric utilities contributing 87 percent of the total.

In order to place conventional stationary combustion source emissions in perspective, Table 3 summarizes the air emissions of the criteria pollutants from the combustion sources considered in this study along with other man-made and natural sources of emissions in the United States. Conventional stationary combustion sources are seen to be the largest emitters of sulfur oxides and major emitters of airborne particulates and nitrogen oxides, whereas their contribution to hydrocarbon and carbon monoxide emissions are of minor significance.

Trace element emissions to air from all fuels are summarized in Table 4. Electric generation by stationary combustion is again the source of most of these emissions, largely as a result of the combustion of coal. Although not shown by the table, only cadmium, cobalt, copper, nickel, and vanadium, of the 28 trace elements tabulated, are produced in appreciable quantities by burning oil. Analysis of the available emission data indicates that approximately 50 to 80 percent of the combustion source emissions of these elements are attributable to oil combustion.

Sources of trace metal element emissions to water are ash pond discharge, cooling tower waters, and waste water from boiler water treatment processes. Because of differences in system design and operating practices, trace element emissions to water exhibit large variability. Because of this variability, and the lack of sufficient emissions data, it has not been possible to compile trace element data for water such as that presented in Table 4 for air. However, it is estimated that over 95 percent of trace metals from combustion sources (and over 90 percent of organic compounds), are the result of electric utility operations. The utility industry is estimated to contribute 14 percent of the total national discharge of metals, including 50, 14, 10 and 21 percent, respectively, of chromium, copper, iron, and zinc discharged, by industries designated as major water pollutant sources by EPA.[4]

Table 3. MAGNITUDE OF AIR EMISSIONS FROM CONVENTIONAL STATIONARY COMBUSTION SOURCES COMPARED TO ALL MAN MADE AND NATURAL EMISSIONS IN THE U.S.[a]

Source	Particulates			Sulfur oxides			Nitrogen oxides			Hydrocarbons			Carbon monoxide		
	10^6 ton/yr	% of total	% of man-made	10^6 ton/yr	% of total	% of man-made	10^6 ton/yr	% of total	% of man-made	10^6 ton/yr	% of total	% of man-made	10^6 ton/yr	% of total	% of man-made
Nature[b]	U[c]	U	-	4.2	11.9	-	U	U	-	30.7	45.5	-	NONE	0	-
Stationary Combustion	7.1	U	20.4	22.1	62.6	71.0	11.0	U	44.3	0.4	0.5	1.0	1.1	0.7	0.7
Transportation	0.8	U	2.3	1.1	3.1	3.5	11.2	U	45.2	19.8	29.3	53.7	111.5	74.0	74.0
Industrial Processes	14.4	U	40.5	7.5	21.3	24.2	0.2	U	0.8	5.5	8.1	14.9	12.0	8.0	8.0
Miscellaneous	12.8	U	36.4	0.4	1.1	1.3	2.4	U	9.7	11.2	16.6	30.4	26.1	17.3	17.3
Total	35.1	U	100.0	35.3	100.0	100.0	24.8	U	100.0	67.6	100.0	100.0	150.7	100.0	100.0

[a] Estimates for combustion sources studied in this program were developed by GCA. Other emissions based on Robinson and Robbins[2] and Walther.[3]

[b] Natural emissions estimated by multiplying total natural emissions by the ratio of U.S. to global land surface areas.

[c] U = Unknown.

Table 4. TRACE ELEMENT AIR EMISSIONS: PERCENT OF TOTAL FROM CONVENTIONAL STATIONARY COMBUSTION SYSTEM CATEGORIES

	Sb	As	Ba	Be	Bi	B	Br	Cd	Cl
Electric Generation	87	90	88	89	91	90	84	61	83
Industrial	10	8	9	9	7	9	13	21	13
Commercial/Institutional	3	2	3	2	2	1	2	18	2
Residential	0.05	0.06	0.1	0.06	0.05	0.05	1	0.007	2
Total, tons/year	59	3,300	3,050	260	110	5,500	6,700	330	710,000

	Cr	Co	Cu	F	Fe	Pb	Mn	Hg	Mo
Electric Generation	84	63	72	83	77	92	89	81	74
Industrial	11	23	16	13	20	7	10	14	16
Commercial/Institutional	5	14	12	2	3	1	1	3	10
Residential	0.1	0.3	0.07	2	0.2	0.05	0.5	2	0.05
Total, tons/year	1,800	510	2,800	37,000	170,000	1,300	5,100	59	692

	Ni	Se	Te	Tl	Sn	Ti	U	V	Zn	Zr
Electric Generation	60	85	90	90	75	89	86	63	89	78
Industrial	21	13	9	9	13	9	10	20	10	20
Commercial/Institutional	19	2	1	1	12	2	4	17	1	2
Residential	0.02	1	0.07	0.06	0.1	0.06	0.05	0.02	0.1	0.2
Total, tons/year	8,100	870	31	10	130	62,000	1,700	11,000	2,300	2,300

Electric coal-fired utilities are the principal source of solid waste trace elements. The predominant sources of solid waste trace elements are bottom ash, fly ash and solids produced by SO_2 recovery systems, whose combined production is now approximately 54 million tons per year. This value will increase with increasing coal consumption and will increase several fold if predictions concerning flue gas desulfurization utilization are realized. The trace element content of collected ash is summarized in Table 5.

CONCLUSIONS

The following text highlights some of the major conclusions which we have drawn from the results of this study. In general, the conclusions and interpretations apply to national emission levels; on a local level, any of the combustion categories considered may present a serious environmental problem due to the relative magnitude of the combustion system emissions with respect to other sources and variations in fuel type, size, operating practices, weather patterns, geology, hydrology, and population density.

- Coal combustion is the largest contributor to the air, water, and solid waste burden generated by stationary combustion sources.

- The electric utility sector generates the largest percentage of most air, water, and solid waste pollutants. The large amount of fuel consumed by the utility sector, and specifically the very large amounts of coal burned, accounts for this pollutant production.

- Industrial steam generation, space heating, and stationary engine operation are less significant as pollutant sources than the electric utility sector. One reason is the extensive use of natural gas.

- Commercial/institutional and residential combustion systems are negligible contributors to the total burden of water and solid waste pollutants. They contribute negligible amounts of trace elements and only minor amounts of particulate, SO_x, and NO_x emission to the environment. Coal-fired residential combustion systems

Table 5. TRACE ELEMENTS IN SOLID WASTE (ASH): PERCENT OF TOTAL GENERATED BY CONVENTIONAL STATIONARY COMBUSTION SYSTEM CATEGORIES

	Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
Electric Generation	80.7	88.9	83.2	83.1	84.3	84.6	0	82.6	0	75.1
Industrial	16.4	8.9	13.2	12.5	13.3	12.8	0	14.1	0	11.7
Commercial/Institutional	1.3	0.9	1.4	1.8	0.8	1.1	0	1.4	0	5.4
Residential	1.6	1.6	2.2	2.6	1.6	1.6	0	1.9	0	7.8
Total, tons/year	170	13,500	17,600	812	349	17,900	0	121	0	5,550

	Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni
Electric Generation	69.3	77.6	0	86.9	80.9	97.7	77.9	80.0	80.8
Industrial	8.9	12.1	0	8.8	14.6	1.2	20.2	13.0	12.0
Commercial/Institutional	8.2	4.1	0	1.8	1.8	0.6	1.8	2.6	2.9
Residential	13.7	6.2	0	2.5	2.6	0.4	0.1	4.6	4.3
Total, tons/year	2,120	4,720	0	1,510,000	2,790	13,800	7	1,280	5,180

	Se	Te	Tl	Sn	Ti	U	V	Zn	Zr
Electric Generation	76.0	83.7	83.4	76.1	83.1	84.5	83.6	82.6	85.5
Industrial	22.1	13.1	12.6	12.5	12.8	12.9	13.1	12.8	11.1
Commercial/Institutional	1.0	1.2	1.7	1.4	1.7	1.1	1.3	1.8	1.4
Residential	1.0	1.9	2.4	9.9	2.4	1.6	2.0	2.8	2.1
Total, tons/year	408	99	34	383	197,000	4,970	9,320	7,600	19,000

are, however, the principal source of organic emissions. Within the stationary combustion sources, residential systems are also a large source of hydrocarbon and carbon monoxide emissions.

The following discussion provides more extensive interpretations of the results of this study and specifically enumerates those areas which represent the major data gaps applicable to emissions from conventional stationary combustion systems. A number of general needs are presented first, followed by a listing of areas requiring further study which are specific to air and water emissions and to the generation of solid waste.

- On the basis of the preliminary emissions assessment completed in this program, it is apparent that a need exists for further development and analysis of the data base including: a compilation of critically reviewed and acceptable data; a means of storing and retrieving this data through the development of a computerized data handling system relating combustion systems and pollutants; and the development of software to evaluate the ramifications and significance of trends in fuel consumption and boiler design in order to adequately assess the environmental impact of stationary conventional combustion sources. The Source Test Data System (SOTDAT) could conceivably be used as a central depository for source test data and its subsequent analysis for air emissions, but some modification of the system is needed to insure adequate description of the source.

- Additional research should be conducted on combustion systems utilizing control practices and fuels that are representative of the existing situation or which can be expected to increase in prominence in the future. These investigations should follow the recommendations which are forthcoming from the priority ranking efforts currently being undertaken by Monsanto Research Corporation based on the data base compiled under this contract effort. This approach is important because numerous past programs, such as some dealing with trace element emissions to the air, have dealt with systems that are non-representative of existing combustion sources and/or their control equipment.

- Greater effort should be expended in coordinating research activities within and between government agencies, industrial, academic and trade organizations to ensure that appropriate personnel are cognizant of activities in the area of combustion source emissions.

- Research directed to emissions of particulates, SO_x, NO_x, and trace elements should concentrate on coal combustion by electric utilities. Secondary efforts should be directed towards coal combustion by the industrial sector.

- The importance of trace element emissions from conventional stationary combustion systems cannot be precisely defined. Comparison of concentrations produced to industrial TLV's indicate that for most elements the concentrations produced are well below the TLV values and the emissions should not be particularly hazardous. However, a very large population is exposed and some trace elements produced by combustion tend to concentrate on the surface of respirable fine particulates. In addition trace elements may catalyze atmospheric reactions. Investigations of trace element emissions should continue.

- Fine particulate and vapor phase emissions and control measures should be investigated with emphasis on coal combustion by electric utilities. Scrubber efficiencies should be determined for vapor phase trace elements and POM.

- Emission factors for POM's and PCB's, halogens and SO_3 should be developed for all sectors because of the large uncertainties in the available data. Efforts should initially be concentrated on the residential sector as this sector produces most of the organics and may produce large amounts of SO_3. Coal combustion should receive major attention for POM and PCB. Oil combustion may contribute relatively high amounts of SO_3 and sulfuric acid due to the presence of vanadium catalysts.

- Efforts should be made to improve the efficiency of combustion of small residential and commercial burners to reduce emissions, particularly polycyclic organic emissions.

- Air emissions from flue gas desulfurization units should be evaluated for sulfates, fine particulates, and trace metals.

- Emission factors and control measures for NO_x emissions from stationary internal combustion engines should be further developed.

- Water emission research and development efforts should be directed primarily towards the electric utility sector with secondary efforts directed to the industrial sector. Efforts should also concentrate on coal combustion.

- A better definition of the electric utility and industrial sectors water handling practices should be undertaken. Information in these areas has been difficult to obtain. Federal Power Commission data has been useful for the electric utility sector, but the data should be subjected to further analysis. Data on the practices of the industrial sector are particularly poor and should be improved. The National Pollution Discharge Elimination Permit System should be examined in detail as a potential source of additional information on both electric utility and industrial practices. State agencies may also be able to provide detailed data.

- Ash pond effluents should be characterized with regard to total and suspended solids, including composition of trace elements, organic, and organometallic compounds. Control methods should also be investigated.

- Cooling water practices and effluent concentrations in the industrial sector should be defined.

- The potential contribution of flue gas desulfurization processes to water emissions should continue to receive strong emphasis.

- Product recovery of coal ash (fly ash, bottom ash, and boiler slag) should be implemented to an increased extent.

- Ash handling practices of electric utilities and industrial combustion sources should be examined and the extent of control determined.

- The chemical composition (metals and organics) of coal and ash should be studied in more detail with greater emphasis on sampling and analytical procedures. In addition, although the amount of ash from residual oil is very small, the amount and composition should be investigated as no data are presently available.

- Methods for disposal of desulfurization wastes should be investigated further. Control measures, such as pond liners and stabilizers, should also be investigated.

SECTION II

ELECTRIC UTILITY COMBUSTION SYSTEMS

SIZE OF INDUSTRY, SOURCES OF ENERGY, FUEL CONSUMPTION

Approximately 1,900 x 10^6 MWh of electrical energy was generated in the United States during 1974, of which approximately 1,800 x 10^6 MWh, or 95 percent, was generated by utilities for general consumption. During 1974 fossil fuels produced 79 percent of the total electricity generated, while hydropower and nuclear fuel produced 15 percent and 6 percent, respectively.[5] Seventy-seven percent of installed generation capacity was driven by steam prime movers, 9 percent by internal combustion, and 14 percent by hydropower. Refuse, which is burned in small amounts to produce electricity, is also considered in this report.

Fossil fuel consumption for electricity production increased 5 to 9 percent per year in the period 1968 to 1973 with a total increase of 43 percent. However, from 1973 to 1974 fossil fueled electric production decreased 3.5 percent,[6] due primarily to the sharp increase in energy costs, energy conservation efforts, the recession, and also as a result of increased production from nuclear fuel and hydropower. Table 6 indicates that over the past 7 years coal has been the predominant fossil fuel. Oil's share of the electric utility market has more than doubled since 1968, from 9 to 22 percent while both coal and gas have decreased slightly.

In 1974, 54 percent of the fossil fuel consumed was bituminous coal, 0.25 percent anthracite, 1.3 percent lignite, 23 percent natural gas,

Table 6. UTILITY FOSSIL-FUELED ELECTRICITY PRODUCTION - SOURCE OF ENERGY, PERCENT[a]

Fuel \ Year	1968	1969	1970	1971	1972	1973	1974
Coal	63	60	56	53	53	55	55
Oil	9	12	14	18	21	22	22
Gas	28	28	29	29	27	23	23

[a]Totals may not add due to rounding.

19 percent residual oil, and 2.9 percent distillate oil. The bituminous coal category includes approximately 15 percent subbituminous coal. Included in the natural gas category is less than 0.6 percent combined coke oven gas, refinery gas, and blast furnace gas. The use of liquified natural gas and synthetic natural gas was essentially zero. All heavy oils were included in the residual oil category and consisted of 0.6 percent No. 4, 1.5 percent No. 5, 95.5 percent No. 6, and 2.4 percent crude. Distillate oil consisted primarily of No. 2 fuel oil, and less than 10 percent kerosene and jet fuel. Approximately 96 percent of the consumed fuels were burned in external combustion systems and 4 percent in internal combustion systems. A small undetermined amount of fuel was burned in combined cycle plants consisting of gas turbines followed by waste heat boilers.

External combustion systems (boilers) produced 1419 x 10^6 MWh of electricity in 1974 from an installed capacity of 337,000 MW for a yearly average load factor of 48 percent. In previous years the load factor was 50 to 55 percent. Comparison of the fuel consumed to the electricity produced yields a 1974 heat rate of 10,420 Btu/kWh, equivalent to a heat-to-electricity efficiency of 33 percent.

Internal combustion systems consist of gas turbines and reciprocating engines burning distillate oil and natural gas. A few gas turbines are designed to burn residual and/or crude oil after pretreatment, but no such fuel use was reported for 1974. Fuel used by internal combustion systems was only 3.8 percent of the electric utility total and consisted of almost equal amounts of distillate oil and natural gas. Gas turbines consumed seven times as much fuel as reciprocating engines. The predominant turbine fuel was distillate oil while the predominant reciprocating engine fuel was natural gas. Internal combustion systems are used primarily for peaking, emergency, and reserve power, and therefore had a low yearly average load factor of only 10 percent during 1974. Their heat rate of 14,750 Btu/kWh is higher than that of external combustion systems and equivalent to an average efficiency of 23 percent.

During 1974, Union Electric Company of St. Louis was the only utility in the United States burning refuse to produce electricity.[6] Its capacity was 12.5 tons per hour, and if operated at a 50 percent yearly load factor, produced about 0.066×10^6 MWh of electricity.

Figure 1 presents the geographic distribution of utility fuel consumption during 1973. Most of the fuel (75 percent) is consumed in the eastern half of the United States with Texas (8.4 percent) and California (6.0 percent) also consuming large quantities. Electric utility coal consumption is presented in Figure 2. Coal consumption is concentrated in the eight-state region of Michigan, Illinois, Indiana, Ohio, Pennsylvania, Kentucky, West Virginia, and Tennessee, where 58 percent of the coal is consumed. Oil consumption is concentrated in states along the eastern seaboard including the New England, Middle Atlantic and South Atlantic regions where a total of 72 percent of the oil is consumed. Fifty-three percent of the gas is consumed in the West South Central Region (Arkansas, Louisiana, Oklahoma, and Texas).

Figure 1. Geographical Distribution - Electric Utility Fuel Consumption - 1973.

Figure 2. Geographical Distribution - Electric Utility Coal Consumption - 1973

POPULATION AND CHARACTERISTICS OF COMBUSTION EQUIPMENT

The boiler systems emphasized in this study, and their associated fuel use, are presented in Table 7. The data in Table 7 were derived from the previously discussed fuel use data and from boiler population and characteristics, based primarily on computer analysis of individual boiler data reported to the Federal Power Commission on Form FPC-67 and stored on magnetic tape. All steam-electric plants of 25 MW or greater capacity, which used 97 percent of the fuel consumed by steam-electric plants, are required to complete Form FPC-67. The data gathered from these forms was the most recent (1972) and the best available describing the population of utility boilers.*

Coal-Fired Boilers

The total number of coal-fired utility boilers included in the FPC data was 1082 compared to 1500 reported to be in the National Emission Data System (NEDS) file. The differences in the number of boilers may be due to the fact that NEDS includes boilers of a lower size limit, and that nonutility electric generation boilers are also included in the NEDS system. During 1972 the reported coal-fired utility boiler heat rate was 10,252 Btu per kWh,[7] compared to the GCA calculated design heat rate of 9670 Btu per kWh based on FPC data. The capacity average age+ of coal-fired utility boilers at the end of 1972 was calculated to be 12 years.

The boiler data for coal combustion obtained from the FPC tape, are summarized by major subcategories in Table 8. Almost 70 percent of the installed capacity consists of pulverized dry bottom boilers, approximately 16 percent were pulverized wet and 13 percent were cyclone boilers. Stoker-fired boilers comprised a large segment of the boilers by number

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*FPC data for 1973 should be available for analysis late in 1975.

+Capacity average age = Σ (capacity x age)/Σ capacity.

Table 7. ELECTRIC UTILITY SYSTEM FUEL CONSUMPTION, 1974

Classification system number[a]	Combustion system category	10^{12} Btu
1.0.00.0.0	Electric Generation	15,387
1.1.00.0.0	External Combustion	14,798
1.1.10.0.0	Coal	8,502
1.1.11.0.0	Bituminous	8,264
1.1.11.1.0	Pulverized Dry	5,971
1.1.11.2.0	Pulverized Wet	1,118
1.1.11.3.0	Cyclone	1,118
1.1.11.4.0	All Stokers	57
1.1.12.0.0	Anthracite	38
1.1.12.1.0	Pulverized Dry	13
1.1.12.2.0	Pulverized Wet	0
1.1.12.3.0	Cyclone	0
1.1.12.4.0	All Stokers	25
1.1.13.0.0	Lignite	200
1.1.13.1.0	Pulverized Dry	120
1.1.13.2.0	Pulverized Wet	30
1.1.13.3.0	Cyclone	30
1.1.13.4.0	All Stokers	20
1.1.20.0.0	Petroleum	3,039
1.1.21.0.0	Residual Oil	2,901
1.1.21.0.1	Tangential Firing	1,128
1.1.21.0.2	All Other	1,773
1.1.22.0.0	Distillate Oil	138
1.1.22.0.1	Tangential Firing	54
1.1.22.0.2	All Other	84
1.1.30.0.0	Gas	3,257
1.1.30.0.1	Tangential Firing	791
1.1.30.0.2	All Other	2,466
1.1.40.1.1	Refuse	0.6
1.2.00.0.0	Internal Combustion	589
1.3.00.0.0	Turbine	515
1.3.20.0.0	Petroleum	286
1.3.30.0.0	Gas	229
1.4.00.0.0	Reciprocating	74
1.4.20.0.0	Petroleum	26
1.4.30.0.0	Gas	48

[a]The classification system utilized in this study is presented in Volume II.

Table 8. SUMMARY: COAL-FIRED UTILITY BOILERS - 1972[a]

	Number of boilers percent of total	Capacity percent of total	Coal burned percent of total	Capacity average[b] age, years
Boiler type				
Pulverized dry	57.8	69.5	71.8	10
Pulverized wet	17.1	15.8	13.5	13
Cyclone	6.6	12.6	13.5	8
Stoker	18.4	2.2	1.2	37
Boiler size, 10^6 Btu/hr				
>5000	5.2	27.5	23.2	2
1500-5000	19.2	38.8	44.6	8
500-1500	31.8	23.8	27.1	19
<500	43.9	9.9	5.0	33

[a]Summary of data in Table 14, Volume II

[b]Capacity average age = $\frac{\Sigma \text{ (Capacity x age)}}{\Sigma \text{ Capacity}}$

(18 percent) but only a small segment by capacity (2.2 percent). In addition, stoker-fired boilers were very old with a capacity average age of 37 years compared to the overall average boiler capacity age of 12 years. Boilers above 5,000 x 10^6 Btu/hr were very new (approximately 2 years old), and compared to the number of boilers (5.2 percent), burned a large fraction of the fuel (23 percent).

Pulverized coal-fired boilers burned approximately 85 percent of the coal consumed by the electric utilities. Only 1.3 percent of these boilers (by capacity) used fly ash reinjection. Few utility boilers used vertical firing, 50 percent of the pulverized coal-fired boiler capacity used tangential firing, and 32 percent used front firing. Only 18 percent used opposed firing but these were the largest and newest boilers.

Anthracite coal is most commonly burned in industrial and commercial boilers with stationary or traveling grates. Anthracite is not burned in spreader stokers because of its high ignition temperature, but may be burned as pulverized coal. However, because of ignition problems, this practice is limited to only a few plants in eastern Pennsylvania. Pulverized boilers burning anthracite are all dry bottom due to the very high ash softening temperature, commonly above 2,900°F. It was estimated that anthracite boilers are 65 percent stokers and 35 percent pulverized dry, based on evaluation of NEDS data.

Lignite is burned in all boiler types. Although in the past lignite was burned in small stokers, there has been a recent shift to large pulverized and cyclone type boilers. Most of the large boilers burning lignite were identified through the available FPC data, and it was estimated that 60 percent of the lignite was burned in pulverized dry, 15 percent in pulverized wet, 15 percent in cyclone and 10 percent in stoker-fired boilers.

The characteristics of bituminous coal-fired boilers were similar to all coal-fired boilers, since bituminous coal represents 97 percent of the

coal burned. Pulverized dry boilers accounted for approximately 72.3 percent of the bituminous coal burned, whereas pulverized wet and cyclone boilers accounted for 13.5 percent each, and stokers accounted for approximately 0.7 percent.

Oil- and Gas-Fired Boilers

A similar analysis of the FPC magnetic tape was performed for oil- and gas-fired utility boilers. Boilers were classified as oil-fired if greater than 85 percent of the fuel was oil; gas-fired if greater than 85 percent of the fuel was gas, and if neither of the above conditions applied, the boiler was classified as dual-fired. The data represent approximately 72 percent of oil consumed at steam-electric plants and 83 percent of the gas consumed. Therefore, the data should be representative of the utility industry with the exception that a possibly large number of small boilers are not included.

About 70 percent of the oil burned in steam-electric boilers was burned in boilers classified as oil-fired, while most of the remaining was burned in dual-fired boilers. There was a large difference in the ages of oil-fired boilers between the less than 500×10^6 Btu/hr groups and each of the other large size groups. Oil-fired boilers below 500×10^6 Btu/hr had an average age of about 28 years, while larger boilers had an average age of 14 years. Boilers using opposed firing, although burning only a small fraction of the total oil, were the newest oil-fired boilers. It was previously indicated that the newest coal-fired boilers also used opposed firing.

Table 9 is a summary of the relative amounts of fuel burned by firing pattern and size for oil- and gas-fired boilers. The table shows that approximately 39 percent of the oil is burned in tangentially-fired boilers, and 47 percent is burned in front- or back-fired boilers. In addition, it

Table 9. DISTRIBUTION (%) OF FUEL CONSUMPTION BY FIRING PATTERNS AND SIZE OF UTILITY EXTERNAL COMBUSTION BOILERS USING OIL AND GAS, 1972

Oil		
Firing pattern		
1.1.20.0.0.0	Oil	100.0
1.1.20.0.1.0	Tangential	38.9
1.1.20.0.2.0	All other (except tangential)	61.1
1.1.20.0.3.0	Front or back	46.8
1.1.20.0.4.0	Opposed	11.1
1.1.20.0.9.0	Other	3.2
Size		
1.1.20.0.0.0	Oil	100.0
1.1.20.0.0.1	> 5000 x 10^6 Btu/hr	6.7
1.1.20.0.0.2	1500 - 5000	42.6
1.1.20.0.0.3	500 - 1500	38.0
1.1.20.0.0.4	< 500	12.7
Gas		
Firing pattern		
1.1.30.0.0.0	Gas	100.0
1.1.30.0.1.0	Tangential	24.3
1.1.30.0.2.0	All other (except tangential)	75.7
1.1.30.0.3.0	Front or back	46.8
1.1.30.0.4.0	Opposed	27.6
1.1.30.0.9.0	Other	1.3
Size		
1.1.30.0.0.0	Gas	100.0
1.1.30.0.0.1	> 5000 x 10^6 Btu/hr	10.5
1.1.30.0.0.2	1500 - 5000	48.6
1.1.30.0.0.3	500 - 1500	28.9
1.1.30.0.0.4	< 500	12.0

should be noted that approximately 81 percent of the oil is burned in boilers in the size range 500 to 5,000 x 10^6 Btu/hr.

The boiler sizes and firing methods used for burning gas are similar to those burning oil. The newest boilers are the largest boilers, and in general use opposed firing. The data in Table 9 indicate that 24 percent of the gas is burned in tangentially-fired boilers and 47 percent in front- or back-fired boilers. The largest amount of gas (49 percent) is burned in the 1,500 to 5,000 x 10^6 Btu/hr size range.

Internal Combustion

Internal combustion engines are usually grouped in two classes: gas turbines and reciprocating engines. They are used extensively in the United States for peaking, emergency, and reserve electric generation with some smaller electric utilities using them for base load also. The average yearly load factor is about 10 percent for internal combustion engines used in electric generation. Fuel use by internal combustion engines was only about 4 percent of the electric utility total.

Gas turbines can use a variety of fuels, as long as the fuel used does not form ash or contain dust which can erode the turbine blades. A few gas turbines are designed to burn treated residual oil, but no such fuel use was reported in 1974. Gas turbines used 286 x 10^{12} Btu distillate oil and 229 x 10^{12} Btu gas in 1974. The FPC has compiled detailed data on gas turbines that consumed 90 percent of the gas turbine fuel in 1972. Based on these data, the average plant size was 82 MW (1260 x 10^6 Btu/hr) and there were 299 plants. There were 989 units with an average size of 25 MW (385 x 10^6 Btu/hr). The average gas turbine heat rate is 15,400 Btu/kWh, corresponding to an efficiency of 22 percent.[5]

The fuels used in reciprocating engines include primarily distillate oil (26 x 10^{12} Btu/yr) and natural gas (48 x 10^{12} Btu/yr). The average

reciprocating engine heat rate is 12,000 Btu/kWh, corresponding to an efficiency of 29 percent.

Solid Waste Fired Boilers

The primary solid waste fuels are bagasse, wood bark and municipal refuse. Bagasse, a sugar cane waste material, is used in Hawaii, Florida, and Louisiana to produce steam and electricity, primarily for on-site use. Whereas some electricity produced by bagasse may be sold to electric utilities, there were no documented utility boilers burning bagasse in 1972.

Wood bark waste is used, in various regions of the United States, in the lumber and paper industry for process steam. Electricity is also generated, in some locations, for on-site use. There were no FPC documented utility users of wood bark in the United States in 1972.

The only utility currently burning refuse is the Meramac Plant of Union Electric in St. Louis County.[6] Currently, Union Electric has the capability to use refuse for 10 percent of the fuel requirement in a 125 MW boiler. The boiler is a pulverized coal, tangentially-fired unit with an electrostatic precipitator. The refuse is air classified and metals are removed before it is fired at a rate of 12.5 tons/hr. At a 50 percent load factor (typical of the utility industry), Union Electric would only burn 0.5×10^{12} Btu/yr of refuse. Therefore, at the present time refuse represents an insignificant part of the total utility energy requirement of $15,400 \times 10^{12}$ Btu/yr. Union Electric is currently expanding its refuse combustion capability to 8,000 tons/day (all the refuse generated in the St. Louis area) and, if this program continues to be successful, refuse combustion by the utility sector may be more significant in the future. Full utilization of solid waste (both municipal and agricultural) could supplement the national energy supply by as much as 6 percent.

EMISSION SOURCES

A large number of processes (or unit operations) utilized in the generation of steam and/or electricity generate emissions in the form of air, water or solid waste pollutants. A coal-fired power plant has the largest number of unit processes and emissions points; typical operations and emission sources in a coal-fired electric power plant are presented in Figure 3. Many of the processes and emission points in this figure are not applicable to gas- or oil-fired boilers and most are not applicable to internal combustion engines.

The emission data contained in Volume II of this report is organized around the unit operations presented in Table 10. The waste streams emanating from individual unit process sources are frequently combined and can be treated jointly. Ash handling includes both fly ash and bottom ash.

Table 10. APPLICABILITY OF UNIT OPERATION AND PROCESS TO AIR, WATER, AND SOLID WASTE POLLUTANTS

Unit operation	Air	Water	Solid waste
Flue gas emissions	X	NA	NA
Ash handling	O	X	X
Boiler blowdown	NA	X	O
Equipment cleaning	O	X	O
Water treatment	NA	X	O
Fuel handling	O	X	O
SO_2 scrubbing	NA	X	X
Cooling systems	X	X	NA

Note: X = Source
O = Minor source
NA = Not applicable

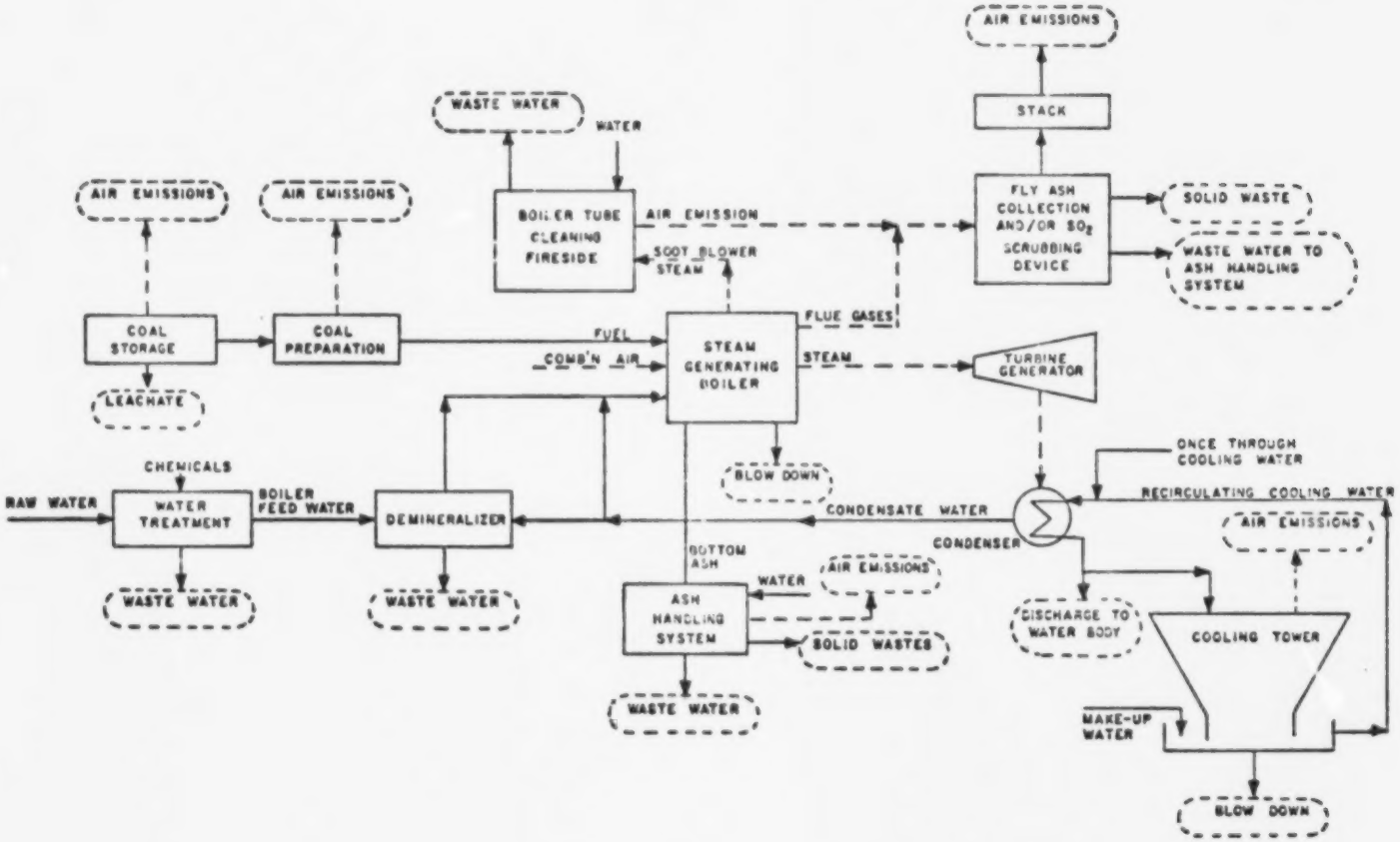

Figure 3. Emission sources coal-fired steam-electric power plants

Air Emissions

Air emissions from electric power plants arise from a number of sources, but primarily from the combustion furnace stack, which is usually fitted with an emission control device. The influence of control device performance, principally electrostatic precipitators in the electric utility industry, on the quantity of particulate emissions is predominant. Emissions and control device performance are principally affected by fuel, boiler type, sulfur content and load factor. Low sulfur fuels decrease the efficiency of precipitators, and the use of these fuels has hastened the development of hot side and wet wall precipitators and other approaches to control of stack emissions.

Other sources of air emissions are those arising from the handling, storage and disposal of coal and ash. These are relatively minor, amounting to less than 1 percent of the stack emissions, and are considered to be largely an in-plant problem. Cooling tower drift is also a minor contributor to air emissions although, under certain meteorological conditions, it could be a source of major local problems.

The electric utility industry's contribution to total man-made and conventional stationary combustion source pollutant emissions were summarized earlier in Tables 2 and 3. Detailed emission estimates for external combustion sources, in the United States, of the criteria pollutants, organics and trace elements, are presented in Table 11. As noted previously, coal combustion is the predominant source on a nationwide basis of most of the pollutants studied in this program. The difference between the values given for electric generation and external combustion represent the contribution of internal combustion sources. Internal combustion is not a major contributor to emissions with the exception of NO_x, with internal combustion accounting for over 8 percent of NO_x emissions from the utility category. The emission factors used in the generation of

Table 11. STACK EMISSIONS FROM THE GENERATION OF ELECTRICITY BY EXTERNAL COMBUSTION, 1974[a]

		Particulates, 10^3 tons/yr		Gases, 10^3 tons/yr				Organics,[i] tons/yr		
		Total	< 3μ[h]	SO_x	NO_x	HC	CO	BSO	PPCN	BaP
1.0.00.0.0	Electric Generation	4,500	1,600	16,000	7,100	120	360	11,000	11	0.8
1.1.00.0.0	External Combustion	4,500	1,600	16,000	6,500	85	270	11,000	11	0.8
1.1.10.0.0	Coal	4,400	1,500	14,000	4,700	64	210	10,000	10	0.75
1.1.11.0.0	Bituminous[b]	4,300	1,500	14,000	4,600	57	200	9,700	10	0.73
1.1.11.1.0	Pulverized Dry	3,500	1,200	10,000	2,400	41	140	7,000	7.3	0.52
1.1.11.2.0	Pulverized Wet	500	180	1,900	760	7.6	26	1,300	1.3	0.1
1.1.11.3.0	Cyclone	250	100	1,900	1,400	7.6	26	1,300	1.3	0.1
1.1.11.4.0	All Stokers	76	12	99	20	1.2	2.6	58	0.06	0.006
1.1.12.0.0	Anthracite[c]	21	6.5	41	12	0.098	1.2	50	0.05	0.004
1.1.12.1.0	Pulverized Dry	17	6.0	15	4.6	0.008	0.26	15	0.015	0.001
1.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0
1.1.12.3.0	Cyclone	0	0	0	0	0	0	0	0	0
1.1.12.4.0	All Stokers	3.8	0.53	26	7.1	0.09	0.95	35	0.035	0.003
1.1.13.0.0	Lignite[d]	82	30	120	72	6.2	6.9	250	0.25	0.02
1.1.13.1.0	Pulverized Dry	50	18	74	42	3.7	3.7	150	15	0.01
1.1.13.2.0	Pulverized Wet	13	4.6	19	10	1.0	1.0	40	4.0	0.003
1.1.13.3.0	Cyclone	11	5.7	19	16	0.93	0.93	38	3.8	0.003
1.1.13.4.0	All Stokers	8.4	1.2	12	3.8	0.63	1.3	25	2.5	0.002
1.1.20.0.0	Petroleum	78	71	1,500	810	19	30	300	0.3	0.02
1.1.21.0.0	Residual Oil[e]	74	67	1,500	770	18	28	300	0.3	0.02
1.1.21.0.1	Tangential Firing	29	26	570	180	7.2	11	130	0.13	0.008
1.1.21.0.2	All Other	45	41	890	590	11	17	170	0.17	0.012
1.1.22.0.0	Distillate Oil[f]	3.9	3.6	16	41	0.99	1.5	14	0.014	0.001
1.1.22.0.1	Tangential Firing	1.5	1.4	6.1	9.6	0.38	0.58	6	0.006	0.0004
1.1.22.0.2	All Other	2.4	2.2	9.6	32	0.61	0.90	8	0.008	0.0006
1.1.30.0.0	Gas[g]	16	14	0.95	960	1.6	27	360	0.35	0.03
1.1.30.0.1	Tangential Firing	3.7	3.5	0.23	120	0.39	6.6	90	0.09	0.008
1.1.30.0.2	All Other	12	11	0.72	840	1.2	20.5	270	0.27	0.022

NOTE: See Volume II, Table 27 for explanation of footnotes.

Table 11 (continued). STACK EMISSIONS FROM THE GENERATION OF ELECTRICITY BY EXTERNAL COMBUSTION, 1974[a]

		Trace elements,[j] tons/yr									
		Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
1.0.00.0.0	Electric Generation	51	3,000	2,700	230	98	5,000	5,600	200	590,000	1,500
1.1.00.0.0	External Combustion	51	3,000	2,700	230	98	5,000	5,600	200	590,000	1,500
1.1.10.0.0	Coal[k]	48	3,000	2,700	220	98	5,000	5,600	54	590,000	1,400
1.1.11.0.0	Bituminous[l]	48	3,000	2,000	220	93	4,900	5,600	54	560,000	1,300
1.1.11.1.0	Pulverized Dry	35	2,200	1,400	160	67	3,500	4,000	39	400,000	930
1.1.11.2.0	Pulverized Wet	6.3	410	270	30	13	660	760	7.3	76,000	180
1.1.11.3.0	Cyclone	6.3	410	270	30	13	660	760	7.3	76,000	180
1.1.11.4.0	All Stokers	0.33	21	14	1.5	0.64	34	39	0.38	3,900	9.3
1.1.12.0.0	Anthracite[m]	0.04	3.7	13	1.1	0.04	0.37	1.5	0.05	2,200	44
1.1.12.1.0	Pulverized Dry	0.01	1.3	4.5	0.38	0.01	0.13	0.51	0.02	770	15
1.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
1.1.12.3.0	Cyclone	0	0	0	0	0	0	0	0	0	0
1.1.12.4.0	All Stokers	0.03	2.4	8.3	0.71	0.03	0.24	0.95	0.03	1,400	29
1.1.13.0.0	Lignite[n]			650	0.71	5.0	130	0.57		25,000	13
1.1.13.1.0	Pulverized Dry			390	0.43	3.0	77	0.36		15,000	7.7
1.1.13.2.0	Pulverized Wet			97	0.11	0.75	19	0.08		3,800	1.9
1.1.13.3.0	Cyclone			97	0.11	0.75	19	0.08		3,800	1.9
1.1.13.4.0	All Stokers			65	0.07	0.5	13	0.06		2,500	1.3
1.1.20.0.0	Petroleum[o]	2.9	22	48	6.8		8.0	12	150	1,200	130
1.1.21.0.0	Residual Oil[p]	2.9	22	48	6.8		8.0	12	150	1,200	130
1.1.21.0.1	Tangential Firing	1.1	8	19	2.6		3.0	4.8	57	450	50
1.1.21.0.2	All Other	1.8	13	29	4.2		5.0	7.5	89	710	80
1.1.22.0.0	Distillate Oil[q]	ND	0.16	ND				0.04	ND		ND
1.1.22.0.1	Tangential Firing	ND	0.04	ND				0.01	ND		ND
1.1.22.0.2	All other	ND	0.12	ND				0.03	ND		ND
1.1.30.0.0	Gas[r]										
1.1.30.0.1	Tangential Firing										
1.1.30.0.2	All other										

NOTE: See Volume II, Table 27 for explanation of footnotes.

Table 11 (continued). STACK EMISSIONS FROM THE GENERATION OF ELECTRICITY BY EXTERNAL COMBUSTION, 1974[a]

		Trace elements,[j] tons/yr									
		Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni	Se
1.0.00.0.0	Electric Generation	320	2,000	31,000	131,000	1,200	4,500	48	510	4,900	740
1.1.00.0.0	External Combustion	320	2,000	31,000	131,000	1,200	4,500	48	510	4,900	740
1.1.10.0.0	Coal[k]	160	1,300	31,000	131,000	1,200	4,500	47	350	1,300	730
1.1.11.0.0	Bituminous[l]	140	1,200	31,000	130,000	1,200	4,300	47	340	1,300	730
1.1.11.1.0	Pulverized Dry	100	860	22,000	93,000	860	3,100	34	240	930	520
1.1.11.2.0	Pulverized Wet	19	160	4,100	18,000	160	590	6.3	46	180	99
1.1.11.3.0	Cyclone	19	160	4,100	18,000	160	590	6.3	46	180	99
1.1.11.4.0	All Stokers	1.0	8.2	210	930	8.1	29	0.33	2.4	9.3	5.1
1.1.12.0.0	Anthracite[m]	13	27	160	1,000	4.6	5.1	0.40	3.7	18	0.20
1.1.12.1.0	Pulverized Dry	4.6	9.6	56	350	1.6	1.8	0.14	1.3	6.4	0.07
1.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
1.1.12.3.0	Cyclone	0	0	0	0	0	0	0	0	0	0
1.1.12.4.0	All Stokers	8.5	18	100	650	3.0	3.3	0.26	2.4	12	0.13
1.1.13.0.0	Lignite[n]	5.5	26			28	170		4.9	8.7	
1.1.13.1.0	Pulverized Dry	3.3	15			17	100		2.9	5.2	
1.1.13.2.0	Pulverized Wet	0.82	3.9			4.1	26		0.73	1.3	
1.1.13.3.0	Cyclone	0.82	3.9			4.1	26		0.73	1.3	
1.1.13.4.0	All Stokers	0.55	2.6			2.8	17		0.49	0.87	
1.1.20.0.0	Petroleum[o]	160	720	0.29	520	2.9	12	1.4	160	3,600	9.9
1.1.21.0.0	Residual Oil[p]	160	720	0.29	520	2.9	12	1.4	160	3,600	9.9
1.1.21.0.1	Tangential Firing	63	280	0.11	200	1.1	4.4	0.6	64	1,400	3.9
1.1.21.0.2	All Other	98	440	0.18	320	1.8	7.2	0.8	100	2,200	6.0
1.1.22.0.0	Distillate Oil[q]		0.08				0.020	ND		ND	ND
1.1.22.0.1	Tangential Firing		0.032				0.008	ND		ND	ND
1.1.22.0.2	All Other		0.048				0.012	ND		ND	ND
1.1.30.0.0	Gas[r]										
1.1.30.0.1	Tangential Firing										
1.1.30.0.2	All Other										

NOTE: See Volume II, Table 27 for explanation of footnotes.

Table 11 (continued). STACK EMISSIONS FROM THE GENERATION OF ELECTRICITY BY EXTERNAL COMBUSTION, 1974[a]

		Trace elements,[j] tons/yr							
		Te	Tl	Sn	Ti	U	V	Zn	Zr
1.0.00.0.0	Electric Generation	28	9.3	100	55,000	1,500	6,700	2,000	1,800
1.1.00.0.0	External Combustion	28	9.3	100	55,000	1,500	6,700	2,000	1,800
1.1.10.0.0	Coal[k]	28	9.3	98	55,000	1,400	2,600	2,000	1,800
1.1.11.0.0	Bituminous[l]	28	9.3	88	55,000	1,400	2,600	2,000	1,700
1.1.11.1.0	Pulverized Dry	20	6.7	63	39,000	1,000	1,900	1,400	1,200
1.1.11.2.0	Pulverized Wet	3.8	1.3	12	7,400	190	350	270	230
1.1.11.3.0	Cyclone	3.8	1.3	12	7,400	190	350	270	230
1.1.11.4.0	All Stokers	0.20	0.064	0.64	380	9.9	18	14	12
1.1.12.0.0	Anthracite[m]	0.04	0.04	0.37	220	0.11	5.7	12	6.8
1.1.12.1.0	Pulverized Dry	0.01	0.01	0.13	77	0.04	2.0	4.2	2.4
1.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0
1.1.12.3.0	Cyclone	0	0	0	0	0	0	0	0
1.1.12.4.0	All Stokers	0.03	0.03	0.24	140	0.07	3.7	7.8	4.4
1.1.13.0.0	Lignite[n]			10			32	5.8	100
1.1.13.1.0	Pulverized Dry			5.5			19	3.5	60
1.1.13.2.0	Pulverized Wet			1.4			4.8	0.86	15
1.1.13.3.0	Cyclone			1.4			4.8	0.86	15
1.1.13.4.0	All Stokers			0.92			3.3	0.58	10
1.1.20.0.0	Petroleum[o]			6.4	390	100	4,100	5.6	
1.1.21.0.0	Residual Oil[p]			0.08	390	100	4,100	5.6	
1.1.21.0.1	Tangential Firing			0.032	150	39	1,600	2.2	
1.1.21.0.2	All Other			0.048	240	60	2,500	3.4	
1.1.22.0.0	Distillate Oil[q]			6.4			ND	ND	
1.1.22.0.1	Tangential Firing			2.5			ND	ND	
1.1.22.0.2	All Other			3.9			ND	ND	
1.1.30.0.0	Gas[r]								
1.1.30.0.1	Tangential Firing								
1.1.30.0.2	All Other								

NOTE: See Volume II, Table 27 for explanation of footnotes.

Table 11, and sources of necessary supplementary data and the methodologies used to develop emissions, are described in detail in Volume II of this report.

Discussions on the extent and quality of emission estimates are presented in Volume II for each major class of pollutants. National emission estimate data quality is considered to be generally fair to good for the criteria pollutants and poor for organics and trace elements. Organic emission estimates are classified as poor because of both the limited amount of data available and its questionable validity. The trace element emission quality rating of poor is attributable mainly to the questionable validity of extrapolations from the limited amount of available good data to national totals.

Water Effluents

The major wastewater streams associated with coal-fired utility plants are depicted in Figure 4. The flow volumes presented are typical for a 1,000 MW coal-fired plant but are subject to substantial plant-to-plant variations. The figure illustrates that cooling water and ash pond discharge are the principal sources of waste water associated with steam electric generation utilities. To place the various emission streams of fossil fueled utility boilers in the proper perspective, the total volume of waste water emitted and the estimated solids content of the various waste streams are given in Table 12. Many of the intermittent minor sources may present severe problems if adequate control measures are not followed.

Waste waters produced by a steam electric power plant result from a number of on-site operations. Some wastes are discharged continuously while other wastes are produced intermittently, but on a fairly regularly scheduled basis, such as daily or weekly. Waste water is produced

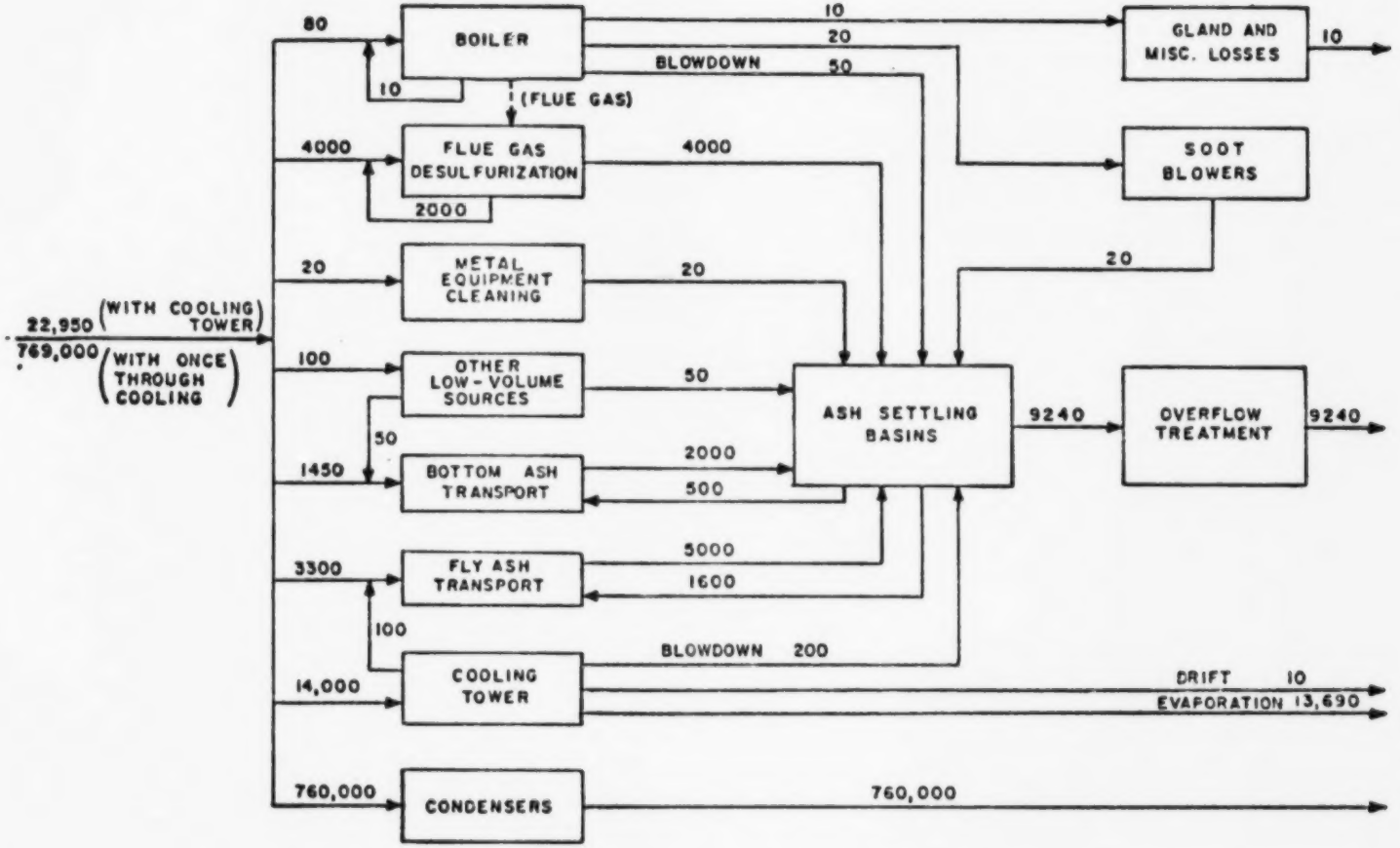

Figure 4. Water flows for a typical 1000 MW power plant at full load. All flow values in 10^3 gpd

Table 12. IMPORTANT ASPECTS OF WATER WASTES

Waste generating process	Duration of flow	Waste water flow quantities: All boilers — 10^9 gal/yr	All boilers — Total solids 10^3 ton	Coal-fired boilers — 10^9 gal/yr	Coal-fired boilers — Total solids 10^3 ton	Important pollutional characteristics	Associated[a,b] hazardous ambient effects	Overall assessment of hazard
Ash handling	Continuous	240[d]	2400	240[c]	2400	300-1500 mg/ℓ TSS trace elements and organics	Possible D.O. reduction production of color, turbidity, and odor. Interference with water reuse.	The quantity of flow and solids concentration is high. With conventional ponding and lagooning of ash wastes, the solids concentration is significantly reduced. The average effluent TSS is 100 mg/ℓ.[e]
Cooling								
Once-through						ΔT -15°F free Cl residual 0.1-1.0 mg/ℓ	D.O. reduction resulting in fish kills and lowered capacity for natural water processes.	Significant hazard with both systems. The large flow quantity is the major cause of the adverse impact.
Fresh	Continuous	33,000[d]		23,000[d]				
Saline	Continuous	16,000		1,600				
Recirculative	Continuous	5,300	275	2,700	140			
Fuel handling	Intermittent	7.9[c,d]	670	7.9[c,d]	670	10-28,000 mg/ℓ acidity 1500-45,000 mg/ℓ TS	Hazards to fish and impairment of water for recreational and consumptive use. Possible D.O. reduction.	Minor ambient hazards for properly collected and treated waste flows. Shock effects may be significant for underdesigned systems and/or prolonged rainfall.
Boiler feedwater treatment	Continuous	9.0[c]	1100	5.2[c]	640	30,000 mg/ℓ TS 3,000 mg/ℓ hardness	Possible D.O. reduction production of color turbidity, and odor. Interference with water reuse.	The waste generated is no greater than that present in the influent water, but it is considerably more concentrated. Lagooning and sedimentation combined with a low flow volume give rise to an overall waste which is nonhazardous.
Boiler blowdown	Intermittent	6.6[c]	5.6	3.8[c]	3.2	5-50 mg/ℓ phosphates 10-100 mg/ℓ alkalinity	Eutrophication and solids sedimentation.	The phosphate concentration is well above values reported to cause nuisance algal blooms. The effect may be particularly severe in impounded waters. The low flow quantity relieves the situation.
Equipment cleaning	Infrequent once/2 yr.	2.2[c]	130	1.3[c]	77	4,000 mg/ℓ hardness 14,000 mg/ℓ TS	Possible D.O. reduction production of color turbidity, and odor. Interference with water reuse.	The extreme infrequency of discharge transforms this into a problem of controlling intermittent, but substantial shock effects in the ambient water.

[a] Fair, G. M., J. C. Geyer, D. A. Okun. Water Purification and Waste Water Treatment and Disposal: Volume II of Water and Waste Water Engineering. John Wiley and Sons. 1968.

[b] McCauley, P. H. Engineering Management of Water Quality. McGraw-Hill Book Co. 1968.

[c] Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. EPA 440/1-74-029a. October 1974.

[d] Edison Electric Institute. A Summary of the Processes Involved and the Chemical Discharges Associated with the Electric Utility Industry.

[e] Steam Electric Plant Air and Water Quality Data. Summary Report FPC-S-238.

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continuously from the following sources: cooling water systems, ash handling systems, wet scrubber flue gas systems, and boiler feedwater treatment. Waste water is discharged intermittently, on a regular basis, by treatment operations such as boiler blowdown and boiler system equipment cleaning. Other wastes are also produced intermittently, but at less frequent intervals, and are generally associated with either the shutdown or startup of a boiler or generating unit. Additional wastes exist that depend upon climatological or other factors, an example of which is coal pile drainage.

Cooling systems use large volumes of water as the medium for cooling boiler generated steam as it passes through the steam condensers. Cooling is accomplished by using recirculative or once-through methods. Recirculative systems consist of various types of cooling towers, cooling ponds, and spray ponds. These systems are essentially closed loops in which used cooling water is cooled for reuse in order to minimize makeup water requirements and eliminate thermal water pollution. Cooling towers contribute significant amounts of moisture and heat to the atmosphere, as well as drifts containing salt, corrosion inhibitors and algicides, such as chlorine, that are added to the recirculating cooling water. Tower blowdown, which is used to control dissolved and suspended solid concentration in the cooling water, adds to the wastewater stream as shown in Figure 4. Cooling canals or ponds are controlled volumes used for storage, cooling, and reuse of cooling water. Spray cooling ponds utilize spray nozzles at the water surface which spray heated water into the air to increase the rate of cooling. The potential exists for emission of salt drift and production of fog, but the problem is more localized than in the case of cooling towers due to the low effective emission height.

In once-through systems, cooling water is passed to the condensers to cool the working fluid and the cooling water is then discharged back to the source. Once-through systems potentially contribute to thermal pollution and the contamination of waters downstream of the plant with additives such

as chlorine (used to prevent fouling of condenser surfaces). An apparent trend is toward the use of wet/dry combination and dry cooling systems in order to reduce water consumption, pollutant discharge and abatement of fogs caused by vapor plumes.

The wastewater volumes from boiler blowdown, coal storage, drainage, equipment cleaning, and water treatment are relatively small. They may contribute, however, to the discharge of hazardous components (PCB, oil or grease, low or high pH water, vanadium, nickel, etc.), that require further processing to reduce effluents to acceptable levels.

Flue gas desulfurization (FGD) is a potentially large source of water pollutants. Most trace elements in FGD solids are more soluble than similar fly ash constituents and pose a potential water quality hazard if sludge liquor is operated in an open loop mode.

The operation and control practices of the utility industry are subject to large plant-to-plant variations. Limited flow and composition data concerning ash pond discharge, boiler blowdown, and cooling practices are available from the Federal Power Commission. Perhaps the most comprehensive emission data are on file with the National Pollution Discharge Elimination System. However, these data are fragmented and difficult to compile, although some compilations have been made and national emissions of some pollutants have been estimated. The data are highly variable reflecting differences in system design and operating practices, and extrapolation of limited data to national averages are highly questionable; thus the emission estimate data quality factors assigned to most waste water streams are generally poor.

Solid Waste Generation

Ash is the principal source of solid waste, accounting for almost 50 million tons per year with coal combustion constituting over 90 percent of this total (see Table 13). Approximately 15 percent of this ash is utilized,

Table 13. ASH HANDLING EMISSIONS: ELECTRIC UTILITIES, 1974

		Bottom ash, 10^3 tons	Fly ash, 10^3 tons	Total, 10^3 tons	Ash utilization, tons	Ponding		Landfill		Water[a] discharge, 10^6 gal/yr	Air emissions, 10^3 tons/yr
						acres/yr	acre feet/yr	acres/yr	acre feet/yr		
1.0.00.0.0	Electric generation	12,925	34,125	47,050	7,500,000	692	17,300	37	876	310,000	20
1.1.00.0.0	External combustion	12,925	34,125	47,050	7,500,000	692	17,300	37	876	310,000	20
1.1.10.0.0	Coal	12,900	34,100	47,000	7,500,000	692	17,300	37	872	310,000	20
1.1.11.0.0	Bituminous	12,550	33,200	45,750	7,300,000	673	17,300	36	850	301,000	19.3
1.1.11.1.0	Pulverized dry	5,350	27,800	33,150	5,300,000	480	17,300	26	610	218,200	14
1.1.11.2.0	Pulverized wet	2,300	3,850	6,150	980,000	90	16,800	5	115	40,300	2.6
1.1.11.3.0	Cyclone	4,700	1,300	6,000	950,000	88	12,200	4	115	39,400	2.5
1.1.11.4.0	All stokers	200	250	450	70,000	7	2,260	1	9	3,100	0.2
1.1.12.0.0	Anthracite	50	100	150	24,000	2.2	2,200	0.2	2.7	985	0.06
1.1.12.1.0	Pulverized dry	15	35	50	8,000	0.7	165	0.05	0.9	314	0.02
1.1.12.2.0	Pulverized wet	0	0	0	0	0	55	0	0	0	0
1.1.12.3.0	Cyclone	0	0	0	0	0	18	0	0	0	0
1.1.12.4.0	All stokers	35	65	100	16,000	1.5	0	0.15	1.8	671	0.037
1.1.13.0.0	Lignite	300	800	1,100	174,000	16	0	0.8	21	7,160	0.47
1.1.13.1.0	Pulverized dry	180	480	660	105,000	9.6	37	0.5	12	4,300	0.28
1.1.13.2.0	Pulverized wet	45	120	165	26,000	2.4	400	0.12	3.2	1,070	0.07
1.1.13.3.0	Cyclone	45	120	165	26,000	2.4	240	0.12	3.2	1,070	0.07
1.1.13.4.0	All stokers	30	80	110	17,000	1.6	60	0.18	2.3	720	0.05
1.1.20.0.0	Petroleum	25	25	50	Nil	0.9	60	Nil	Nil	400	Nil
1.1.21.0.0	Residual oil	25	25	50	Nil	0.9	40	Nil	Nil	400	Nil
1.1.21.0.1	Tangential firing	10	10	20	Nil	0.4	23	Nil	Nil	180	Nil
1.1.21.0.2	All other	15	15	30	Nil	0.5	23	Nil	Nil	220	Nil
1.1.22.0.0	Distillate oil	Nil	Nil	Nil	Nil	Nil	9	Nil	Nil	Nil	Nil
1.1.22.0.1	Tangential firing	Nil	Nil	Nil	Nil	Nil	14	Nil	Nil	Nil	Nil
1.1.22.0.2	All other	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
1.1.30.0.0	Gas	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
1.1.30.0.1	Tangential firing	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
1.1.30.0.2	All other	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil

[a]See Volume II, Tables 47 and 48, for properties of discharge waters.

while the remainder is ultimately disposed of in landfills along with the settled solids from other waste streams that are collected in settling basins or ponds. Although limited data are available concerning leachates, the extent of contamination of ground and surface waters will depend upon many factors including: control measures (ground covers, liners, fixation, etc.); type of fuel used; and local meteorological, hydrological and geological conditions. National estimates of the trace metal content of collected ash from coal-fired electric utilities are given in Table 14.

The solid waste disposal problems associated with combustion systems will drastically increase if flue gas desulfurization processes become widely implemented. For example, if estimates of about 70,000 MW of flue gas desulfurization capacity by 1985 are realized, a total of 100,000,000 tons per year of sludge and ash would be produced. The flue gas desulfurization sludge does not compact as well as ash and, because of its higher sulfur content, compounds in the sludge are more soluble than fly ash constituents. Some constitutent solubilities have been measured which are substantially in excess of desirable water quality criteria. These include mercury, selenium, boron, chloride, sulfate and total dissolved solids. Chemical fixation is receiving extensive study as a means of reducing leachate problems.

Table 14. ASH TRACE ELEMENTS: ELECTRIC UTILITIES, 1974[a]

	Bituminous	Anthracite	Lignite
Sb	138	0.11	–
As	12,000	10.9	–
Ba	11,500	72	3,100
Be	670	3.3	2.1
Bi	279	0.11	15
B	14,800	1.1	380
Br	0	0	0
Cd	99	1.0	–
Cl	0	0	0
Cr	4,000	131	38
Co	1,300	118	50
Cu	3,500	83	77
F	0	0	0
Fe	1,200,000	8,900	–
Pb	2,200	8.4	51
Mn	13,000	15.3	520
Hg	5	0.4	–
Mo	1,000	11	14.5
Ni	4,100	55	26
Se	310	0.1	–
Te	83	0.11	–
Tl	28	0.11	–
Sn	265	1.1	27
Ti	163,000	650	–
U	4,200	0.4	–
V	7,700	13	75
Zn	6,100	36	140
Zr	15,300	63	900

[a]Tons collected.

SECTION III

INDUSTRIAL COMBUSTION SYSTEMS

FUEL CONSUMPTION

Within the fuel use categories considered in this study industrial sources consume 29 percent of the fuel, as shown in Table 1. Approximately 67 percent of the fuel used in industrial combustion applications is natural gas whereas oil and coal account for 18 and 12 percent, respectively. Wood and bagasse represent the remaining 3 percent of industrial fuel consumption. These estimates of industrial fuel consumption were based on Bureau of Mines statistics (coal, oil and gas) and NEDS data (wood and bagasse).

The use of internal combustion engines is more prevalent in the industrial sector than in the electric utility sector. Internal combustion engines account for almost 25 percent of industrial fuel use[8] as opposed to 4 percent in electric utilities. Their greater use is largely based on their adaptability to required variations in demand and their simplicity of operation.

POPULATION AND CHARACTERISTICS OF COMBUSTION EQUIPMENT

The number of industrial boilers and plants is much greater than the number of utility boilers, although a complete accounting of these boilers is not available. Estimates of boiler population and characteristics have been made based on analysis of NEDS data, supplemented by boiler sales information. An estimate of the number of boilers, in operation

in the United States, and their sizes is presented in Table 15. Boiler capacities and fuel consumption by the combustion system classification considered in the study are shown in Table 16.

Table 15. NUMBER AND SIZE OF INDUSTRIAL BOILERS, 1973

Size 10^6 Btu/hr	Number of boilers[a]			
	Coal	Oil	Gas	All fuels
10-20	670	21,000	11,000	32,670
20-50	860	4,600	8,900	14,360
50-100	930	2,500	4,900	8,330
100-200	870	1,100	1,500	3,470
200-500	830	600	570	2,000
> 500	70	135	90	90
Totals	4,230	29,935	26,960	61,125

[a]Includes boilers designed to burn the primary fuel only as well as those capable of burning a secondary fuel.

EMISSIONS

Air Emissions

Emission estimates for industrial boilers operating in the United States are presented in Table 17. Emissions from industrial fuel consumption are governed by the same principles as the electric utility sector; however, because the combustion equipment design and operating practices are different, the emission factors are different. Generally industrial combustion equipment is smaller and is operated less efficiently than electric utility systems. Emission rates of nitrogen oxides tend to be lower due to decreased furnace temperatures; emission rates of hydrocarbons, carbon monoxide, and organics tend to be higher due to less complete

Table 16. INDUSTRIAL BOILER CAPACITY AND FUEL CONSUMPTION BY COMBUSTION SYSTEM, 1973

		Approximate design capacity, 10^9 Btu/hr steam	Fuel consumed, 10^{12} Btu/yr
2.0.00.0.0	Industrial	3,700	11,280
2.1.00.0.0	External combustion	3,230	8,540
2.1.10.0.0	Coal	730	1,370
2.1.11.0.0	Bituminous	690	1,320
2.1.11.1.0	Pulverized dry	330	650
2.1.11.2.0	Pulverized wet	70	130
2.1.11.3.0	Cyclone	10	40
2.1.11.4.0	All stokers	280	500
2.1.11.5.0	Overfeed stokers	25	30
2.1.11.6.0	Spreader stokers	235	450
2.1.11.7.0	Underfeed stokers	20	20
2.1.12.0.0	Anthracite	8	10
2.1.12.1.0	Pulverized dry	0	0
2.1.12.2.0	Pulverized wet	0	0
2.1.12.4.0	All stokers	8	10
2.1.13.0.0	Lignite	20	40
2.1.13.1.0	Pulverized dry	0	0
2.1.13.2.0	Pulverized wet	0	0
2.1.13.4.0	All stokers	20	40
2.1.13.5.0	Overfeed stokers	0	0
2.1.13.6.0	Spreader stokers	20	40
2.1.13.7.0	Underfeed stokers	0	0
2.1.20.0.0	Petroleum	1,110	1,700
2.1.21.0.0	Residual oil	850	1,270
2.1.21.0.1	Tangential firing	140	200
2.1.21.0.2	All other	710	1,070
2.1.22.0.0	Distillate oil	260	430
2.1.22.0.1	Tangential firing	40	70
2.1.22.0.2	All other	220	360
2.1.30.0.0	Gas	1,410	5,200
2.1.30.0.1	Tangential firing	140	520
2.1.30.0.2	All other	1,270	4,680
2.1.40.0.0	Refuse		270
2.1.41.0.0	Bagasse		20
2.1.42.0.0	Wood/Bark		250

Table 17. FLUE GAS EMISSIONS FROM INDUSTRIAL EXTERNAL COMBUSTION, 1973[a]

		Particulates, 10^3 tons/yr		Gases, 10^3 tons/yr				Organics,[i] tons/yr		
		Total	<3μ[k]	SO_x	NO_x	HC	CO	BSO	PPOH	BaP
2.0.00.0.0	Industrial	2,000	200	3,200	2,700	80	160	25,000	20	5
2.1.00.0.0	External Combustion	2,000	200	3,200	1,600	76	150	25,000	20	5
2.1.10.0.0	Coal	2,000	66	2,200	590	17	73	2,800	16	4.0
2.1.11.0.0	Bituminous[b]	1,600	65	2,200	570	16	57	2,700	15	3.8
2.1.11.1.0	Pulverized Dry	610	29	1,100	260	4.3	15	1,200	7.2	1.8
2.1.11.2.0	Pulverized Wet	99	4.8	220	87	0.87	2.9	250	1.4	0.36
2.1.11.3.0	Cyclone	6	3.8	68	49	0.27	0.89	50	0.29	0.072
2.1.11.4.0	All Stokers	900	27	850	170	11	22	1,200	7.7	1.7
2.1.11.5.0	Overfeed Stokers	54	1.5	51	10	0.66	1.3	97	0.56	0.14
2.1.11.6.0	Spreader Stokers	810	24	770	150	9	20	970	5.6	1.4
2.1.11.7.0	Underfeed Stokers	36	1.1	34	6.8	0.44	0.88	97	0.56	0.14
2.1.12.0.0	Anthracite[c]	6.3	0.12	7.3	1.9	0.055	1.7	19	0.11	0.028
2.1.12.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0
2.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0
2.1.12.4.0	All Stokers	6.3	0.12	7.3	1.9	0.055	1.7	19	0.11	0.028
2.1.13.0.0	Lignite[d]	35	0.68	25	18	1.4	14	90	0.52	0.13
2.1.13.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0
2.1.13.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0
2.1.13.4.0	All Stokers	35	0.68	25	18	1.4	14	90	0.52	0.13
2.1.13.5.0	Overfeed Stokers	0	0	0	0	0	0	0	0	0
2.1.13.6.0	Spreader Stokers	35	0.68	25	18	1.4	14	90	0.52	0.13
2.1.13.7.0	Underfeed Stokers	0	0	0	0	0	0	0	0	0
2.1.20.0.0	Petroleum[e]	120	110	1,000	430	15	21	11,000	1.4	0.36
2.1.21.0.0	Residual Oil	97	87	1,000	320	11	15	8,600	1.1	0.27
2.1.21.0.1	Tangential Firing	15	14	160	27	2	3	940	0.12	0.03
2.1.21.0.2	All Other	82	73	840	290	9	12	7,600	0.96	0.24
2.1.22.0.0	Distillate Oil	21	19	41	110	4.2	5.7	2,400	0.38	0.094
2.1.22.0.1	Tangential Firing	3	3	6	10	0.66	0.89	280	0.044	0.011
2.1.22.0.2	All Other	19	16	35	100	3.5	4.8	2,100	0.33	0.083
2.1.30.0.0	Gas[f]	25	23	1.4	420	7.7	41	11,000	2.2	0.55
2.1.30.0.1	Tangential Firing	2.5	2.3	0.14	42	0.77	4.1	2,000	0.4	0.10
2.1.30.0.2	All Other	22	21	1.3	380	6.9	37	9,000	1.8	0.45
2.1.41.0.0	Bagasse[g]	42		0	5.5	5.5	5.5			
2.1.42.0.0	Wood/Bark[h]	210		18	140	31	44			

NOTE: See Volume II, Table 91 for explanation of footnotes.

Table 17 (continued). FLUE GAS EMISSIONS FROM INDUSTRIAL EXTERNAL COMBUSTION, 1973[a]

		Trace elements,[j] tons/yr									
		Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
2.0.00.0.0	Industrial	5.8	260	490	25	9.1	490	870	67	93,000	200
2.1.00.0.0	External Combustion	5.8	260	490	25	9.1	490	870	67	93,000	200
2.1.10.0.0	Coal[k]	4.5	250	470	22	9.1	490	860	3.7	92,000	140
2.1.11.0.0	Bituminous[l]	4.5	250	330	22	9.0	470	860	3.7	86,000	130
2.1.11.1.0	Pulverized Dry	2.3	130	170	11	4.5	240	420	1.9	42,000	65
2.1.11.2.0	Pulverized Wet	0.34	19	25	1.6	0.69	36	85	0.28	8,500	9.9
2.1.11.3.0	Cyclone	0.022	1.2	1.6	0.11	0.043	2.3	11	0.018	2,600	0.63
2.1.11.4.0	All Stokers	1.8	100	130	8.8	3.7	190	330	1.5	33,000	53
2.1.11.5.0	Overfeed Stokers	0.11	6.1	8.0	0.52	0.22	12	20	0.090	2,000	3.1
2.1.11.6.0	Spreader Stokers	1.6	92	120	7.8	3.3	170	290	1.3	29,000	47
2.1.11.7.0	Underfeed Stokers	0.072	4.0	5.2	0.34	0.14	7.6	13	0.059	1,300	2.1
2.1.12.0.0	Anthracite[m]		0.04	3.4	0.17			0.37		550	7.0
2.1.12.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0	0
2.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
2.1.12.4.0	All Stokers	0	0.04	3.4	0.17	0	0	0.37		550	7.0
2.1.13.0.0	Lignite[n]		0	140	0.13	0.08	19	0.036		5,500	1.9
2.1.13.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0	0
2.1.13.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
2.1.13.4.0	All Stokers			140	0.13	0.08	19	0.036		5,500	1.9
2.1.13.5.0	Overfeed Stokers	0	0	0	0	0	0	0	0	0	0
2.1.13.6.0	Spreader Stokers			140	0.13	0.08	19	0.036		5,500	1.9
2.1.13.7.0	Underfeed Stokers	0	0	0	0	0	0	0	0	0	0
2.1.20.0.0	Petroleum	1.3	11	21	3.0		3.6	5.8	63	530	58
2.1.21.0.0	Residual Oil[o]	1.3	10	21	3.0		3.6	5.7	63	530	58
2.1.21.0.1	Tangential Firing	0.20	1.6	3.3	0.47		0.56	0.89	9.9	83	9.1
2.1.21.0.2	All Other	1.1	8.4	18	2.5		2.9	4.9	53	450	49
2.1.22.0.0	Distillate Oil[p]	ND	0.50	ND				0.11	ND		ND
2.1.22.0.1	Tangential Firing	ND	0.034	ND				0.018	ND		ND
2.1.22.0.2	All Other	ND	0.37	ND				0.092	ND		ND
2.1.30.0.0	Gas[q]										
2.1.30.0.1	Tangential Firing										
2.1.30.0.2	All Other										
2.1.41.0.0	Bagasse										
2.1.42.0.0	Wood/Bark										

NOTE: See Volume II, Table 91 for explanation of footnotes.

Table 17 (continued). FLUE GAS EMISSIONS FROM INDUSTRIAL EXTERNAL COMBUSTION, 1973[a]

		Trace elements,[j] tons/yr									
		Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni	Se
2.0.00.0.0	Industrial	110	460	4,800	33,000	86	510	8.1	110	1,700	110
2.1.00.0.0	External Combustion	110	460	4,800	33,000	86	510	8.1	110	1,700	110
2.1.10.0.0	Coal[k]	42	130	4,800	32,000	85	510	7.4	34	130	110
2.1.11.0.0	Bituminous[l]	34	120	4,700	32,000	81	480	7.3	33	130	110
2.1.11.1.0	Pulverized Dry	17	58	2,300	16,000	41	210	3.6	17	65	55
2.1.11.2.0	Pulverized Wet	2.6	8.7	460	2,400	6.2	31	0.72	2.5	9.9	11
2.1.11.3.0	Cyclone	0.17	0.57	140	250	0.40	15	0.22	0.16	0.63	3.4
2.1.11.4.0	All Stokers	14	47	1,800	13,000	33	180	2.8	13	53	42
2.1.11.5.0	Overfeed Stokers	0.82	2.8	110	760	2.0	10	0.17	0.80	3.1	2.5
2.1.11.6.0	Spreader Stokers	12	41	1,600	11,000	29	160	2.5	12	47	38
2.1.11.7.0	Underfeed Stokers	0.54	1.8	70	500	1.3	6.6	0.11	0.52	2.1	1.7
2.1.12.0.0	Anthracite[m]	5.6	4.6	59	420	0.56	0.84	0.091	0.04	3.0	0.051
2.1.12.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0	0
2.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
2.1.12.4.0	All Stokers	5.6	4.6	59	420	0.56	0.84	0.091	0.04	3.0	0.051
2.1.13.0.0	Lignite[n]	2.5	4.2			3.0	25		0.7	1.4	
2.1.13.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0	0
2.1.13.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
2.1.13.4.0	All Stokers	2.5	4.2			3.0	25		0.7	1.4	
2.1.13.5.0	Overfeed Stokers	0	0	0	0	0	0	0	0	0	0
2.1.13.6.0	Spreader Stokers	2.5	4.2			3.0	25		0.7	1.4	
2.1.13.7.0	Underfeed Stokers	0	0	0	0	0	0	0	0	0	0
2.1.20.0.0	Petroleum	70	330	0.13	235	1.3	5.0	0.65	72	1,600	4.5
2.1.21.0.0	Residual Oil[o]	70	330	0.13	235	1.3	5.0	0.65	72	1,600	4.5
2.1.21.0.1	Tangential Firing	11	52	0.020	37	0.20	0.79	0.10	11	250	0.71
2.1.21.0.2	All Other	59	280	0.11	200	1.1	4.2	0.55	61	1,300	3.8
2.1.22.0.0	Distillate Oil[p]		0.25				0.066	ND		ND	ND
2.1.22.0.1	Tangential Firing		0.016				0.011	ND		ND	ND
2.1.22.0.2	All Other		0.023				0.055	ND		ND	ND
2.1.30.0.0	Gas[q]										
2.1.30.2.1	Tangential Firing										
2.1.30.0.2	All Other										
2.1.41.0.0	Bagasse										
2.1.42.0.0	Wood/Bark										

NOTE: See Volume II, Table 91 for explanation of footnotes.

Table 17 (continued). FLUE GAS EMISSIONS FROM INDUSTRIAL EXTERNAL COMBUSTION, 1973[a]

		Trace elements,[j] tons/yr							
		Te	Tl	Sn	Ti	U	V	Zn	Zr
2.0.00.0.0	Industrial	2.8	0.90	18	5,600	180	2,100	220	460
2.1.00.0.0	External Combustion	2.8	0.90	16	5,600	180	2,100	220	460
2.1.10.0.0	Coal[k]	2.8	0.90	9.9	5,400	140	260	210	460
2.1.11.0.0	Bituminous[l]	2.8	0.90	8.6	5,400	140	250	200	420
2.1.11.1.0	Pulverized Dry	1.4	0.45	4.3	2,700	68	130	99	210
2.1.11.2.0	Pulverized Wet	0.21	0.069	0.66	400	10	19	15	32
2.1.11.3.0	Cyclone	0.013	0.0043	0.043	26	0.67	1.2	0.97	2.0
2.1.11.4.0	All Stokers	1.1	0.37	3.5	2,200	55	100	80	170
2.1.11.5.0	Overfeed Stokers	0.065	0.022	0.21	130	3.3	6.0	4.7	10
2.1.11.6.0	Spreader Stokers	0.98	0.33	3.1	1,900	49	90	71	150
2.1.11.7.0	Underfeed Stokers	0.043	0.014	0.14	84	2.2	4.0	3.1	6.7
2.1.12.0.0	Anthracite[m]				35		0.81	2.0	2.9
2.1.12.1.0	Pulverized Dry	0	0	0	0	0	0	0	0
2.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0
2.1.12.4.0	All Stokers				35		0.81	2.0	2.9
2.1.13.0.0	Lignite[n]			1.3			4.2	5.3	39
2.1.13.1.0	Pulverized Dry	0	0	0	0	0	0	0	0
2.1.13.2.0	Pulverized Wet	0	0	0	0	0	0	0	0
2.1.13.4.0	All Stokers			1.3			4.2	5.3	39
2.1.13.5.0	Overfeed Stokers	0	0	0	0	0	0	0	0
2.1.13.6.0	Spreader Stokers			1.3			4.2	5.3	39
2.1.13.7.0	Underfeed Stokers	0	0	0	0	0	0	0	0
2.1.20.0.0	Petroleum				170	44	1,800	6.0	
2.1.21.0.0	Residual Oil[o]				170	44	1,800	6.0	
2.1.21.0.1	Tangential Firing				27	6.9	280	0.94	
2.1.21.0.2	All Other				140	37	1,500	5.1	
2.1.22.0.0	Distillate Oil[p]			5.6			ND	ND	
2.1.22.0.1	Tangential Firing			0.90			ND	ND	
2.1.22.0.2	All Other			4.7			ND	ND	
2.1.30.0.0	Gas[q]								
2.1.30.0.1	Tangential Firing								
2.1.30.0.2	All Other								
2.1.41.0.0	Bagasse								
2.1.42.0.0	Wood/Bark								

NOTE: See Volume II, Table 91 for explanation of footnotes.

combustion; and SO_x emission rates are virtually the same. Particulate emissions from coal (including many trace element emissions) are strongly affected by control equipment efficiency and application, which are both lower in the industrial sector. Control application increases with increasing boiler size, ranging from a reported 21 percent for the smaller boilers (10-200 x 10^6 Btu/hr) to 70 percent for large boilers (> 500 x 10^6 Btu/hr). Particulate emissions from oil in the industrial sector are essentially uncontrolled and are estimated to be three times as high per unit of fuel as in the utility sector, due largely to the release of unburned carbon. Air emissions from coal pile storage and handling, ash handling and cooling systems are substantially less in the industrial area than similar emissions from utilities. Less coal usage and smaller boiler capacities account for this difference.

Estimated emissions of polycyclic organic matter (POM) in the industrial area are almost an order of magnitude higher per unit of fuel than in the utility sector. POM emissions data should be treated with caution, however, as the estimates are based on a limited number of tests.

The difference in emissions between the industrial and external combustion classification shown in Table 17 represents the contribution of internal combustion engines. Only the emissions of NO_x from internal combustion engines are of nationwide significance, accounting for almost 41 percent of NO_x emissions from industrial combustion systems.

Water Emissions

Waste water emissions from the pertinent unit operations described previously are difficult to define. In arriving at the estimates developed under this contract and presented in detail in Volume II, it has been assumed that operating parameters of large industrial boilers (> 500 x 10^6 Btu/hr) parallel the practices followed by electric utilities. Smaller boiler operating practices have been inferred from recommended operating practices by trade organizations and boiler manufacturers. Basically

the greater use of clean fuels, natural gas and oil, lessens the water pollution problem associated with combustion. The amount of waste water from industrial equipment cleaning, fuel handling and ash handling is reduced significantly. However, the lack of available data and description of operating practices makes estimation of the volumes and composition of wastewater streams extremely questionable.

Solid Waste

The solid waste generated by the industrial sector is far less than that generated by utilities due to the smaller amount of coal burned and the less frequent application of particulate control devices. The total amount of ash collected in 1973 was estimated to be 5.2 million tons, approximately an order of magnitude lower than that collected by the utility sector. This total is comprised of 57 percent bottom ash and 43 percent fly ash. The amount of fly ash generated is estimated to be 4.5 million tons but only about 46 percent is collected.

Ash collected by the industrial sector is almost entirely disposed of as landfill. Although the total amount generated is relatively minor on a nationwide basis, improper disposal can have significant local impact.

SECTION IV

COMMERCIAL/INSTITUTIONAL COMBUSTION SYSTEMS

This major classification of combustion sources was defined on the basis of fuel consumption data rather than boiler size. All boilers in the 0.3 to 10 x 10^6 Btu/hr size range are generally considered to be commercial boilers and have been included as such in this study. However, we have chosen to add some larger institutional boilers to the commerical category because of their inclusion in available fuel consumption statistics. These larger boilers, generally associated with large governmental and institutional facilities, account for about 17 percent of the fuel consumed for space heating by the commercial/institutional sources considered. Estimated fuel consumption by the commercial/institutional sector is shown in Table 18 which indicates that approximately 53 percent of the fuel consumed was gas, whereas oil and coal accounted for 44 and 3 percent, respectively. Fuel consumption by internal combustion engines amounted to about 1 percent of the total fuel used.

Because oil and gas are clean fuels relative to coal, and because of the smaller boiler sizes considered, most pollutant waste streams are small and in many cases nonexistent, e.g., cooling waste discharge, water treatment wastes, ash pond discharge, boiler blowdown, etc. Solid waste emissions, resulting from ash handling, are minor due to the small amount of coal consumed. Air emissions of the criteria pollutants, organics and trace elements from the flue gas stack are shown in Table 19. Even though these estimates are for uncontrolled emissions, the contribution of these sources to nationwide emissions are minor, as shown previously in Tables 2 and 3.

Table 18. COMMERCIAL/INSTITUTIONAL FOSSIL FUEL CONSUMPTION - 1973[a]

		Total all uses 10^{12} Btu/yr	Space heating 10^{12} Btu/yr
3.0.00.0.0	Commercial	5,436	4,449
3.1.10.0.0	Coal	156	156
3.1.11.0.0	Bituminous[b]	100	100
3.1.12.0.0	Anthracite[c]	55	55
3.1.13.0.0	Lignite	1	1
3.1.20.0.0	Petroleum	2,379	2,379
3.1.21.0.0	Residual oil[d]	1,269	1,269
3.1.22.0.0	Distillate oil[e]	1,110	1,110
3.1.30.0.0	Gas[f]	2,901	1,914

[a]External combustion only.

[b]22.4×10^6 Btu/ton.

[c]26.0×10^6 Btu/ton.

[d]146,000 Btu/gal.

[e]140,000 Btu/gal.

[f]Includes 8.5 percent LPG, 1020 Btu/ft^3 (gas); 90,000 Btu/gal (liquid).

Table 19. FLUE GAS EMISSIONS FROM COMMERCIAL/INSTITUTIONAL EXTERNAL COMBUSTION, 1973[a]

		Particulates, 10^3 tons/yr		Gases, 10^3 tons/yr				Organics,[h] tons/yr		
		Total	< 3μ[p]	SO_x	NO_x	HC	CO	BSO	PPOM	BaP
3.0.00.0.0	Commercial	350	150	1,500	800	43	83	20,000	6.8	1.7
3.1.00.0.0	External Combustion	340	150	1,500	770	41	78	20,000	6.8	1.7
3.1.10.0.0	Coal	0.70	4.4	230	30	7.0	25	590	3.5	0.86
3.1.11.0.0	Bituminous[b]	0.50	3.0	210	14	6.8	23	380	2.3	0.56
3.1.11.1.0	Pulverized Dry	0.60	2.0	42	2.8	1.3	4.6	76	0.44	0.11
3.1.11.2.0	Pulverized Wet	4.8	0.08	2.1	0.14	0.067	0.023	3.8	0.022	0.0055
3.1.11.4.0	All Stokers	50	0.97	170	11	5.4	18	300	1.8	0.44
3.1.12.0.0	Anthracite[c]	21	0.41	20	16	0.21	2.1	210	1.2	0.30
3.1.12.4.0	All Stokers	21	0.41	20	16	0.21	2.1	210	1.2	0.30
3.1.12.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0
3.1.13.0.0	Lignite	0	0	0	0	0	0	0	0	0
3.1.13.4.0	All Stokers	0	0	0	0	0	0	0	0	0
3.1.13.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0
3.1.20.0.0	Petroleum	150	140	1,300	630	24	32	15,000	2.0	0.51
3.1.21.0.0	Residual Oil[d]	92	83	1,200	320	12	16	7,500	1.0	0.26
3.1.21.1.0	Tangential Firing	0.73	0.66	9.5	1.3	0.095	0.13	70	0.008	0.0021
3.1.21.0.2	All Other	91	82	1,200	320	12	16	7,400	1.0	0.26
3.1.22.0.0	Distillate Oil[e]	59	53	130	310	12	16	7,500	1.0	0.25
3.1.22.0.1	Tangential Firing	0.59	0.53	1.3	1.6	0.12	0.16	80	0.01	0.0025
3.1.22.0.2	All Other	58	52	130	310	12	16	7,400	1.0	0.25
3.1.30.0.0	Gas[f]	9.1	8.2	0.56	110	7.2	19	4,000	1.3	0.32
3.1.30.0.1	Tangential Firing	0.39	0.35	0.024	4.7	0.31	0.81	180	0.056	0.014
3.1.30.0.2	All Other	8.7	7.9	0.54	105	6.9	18	3,800	1.2	0.31
3.1.42.0.0	Wood/Bark[g]	1.4		0.10	0.69	2.5	2.1			

NOTE: See Volume II, Table 116 for explanation of footnotes.

Table 19 (continued. FLUE GAS EMISSIONS FROM COMMERCIAL/INSTITUTIONAL EXTERNAL COMBUSTION, 1973[a]

		Trace elements,[i] tons/yr									
		Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
3.0.00.0.0	Commercial	1.8	39	60	54	0.96	54	160	59	10,000	79
3.1.00.0.0	External Combustion	1.8	39	60	54	0.96	54	160	59	10,000	79
3.1.10.0.0	Coal[j]	0.55	28	40	2.6	0.95	50	70	0.41	9,900	26
3.1.11.0.0	Bituminous[k]	0.48	27	34	2.3	0.95	50	68	0.40	6,700	13
3.1.11.1.0	Pulverized Dry	0.37	21	26	1.8	0.73	39	13	0.31	1,300	10
3.1.11.2.0	Pulverized Wet	0.015	0.85	1.0	0.072	0.029	1.6	0.68	0.012	68	0.42
3.1.11.4.0	All Stokers	0.09	5.0	6.6	0.43	0.19	9.6	54	0.016	5,400	2.6
3.1.12.0.0	Anthracite[l]	0.011	1.1	6.1	0.31	0.011	0.11	2.2	0.011	3,200	13
3.1.12.4.0	All Stokers	0.011	1.1	6.1	0.31	0.011	0.11	2.2	0.011	3,200	13
3.1.12.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0	0
3.1.13.0.0	Lignite	0	0	0	0	0	0	0	0	0	0
3.1.13.4.0	All Stokers	0	0	0	0	0	0	0	0	0	0
3.1.13.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0	0
3.1.20.0.0	Petroleum	1.2	11	20	2.8		3.3	89	59	500	53
3.1.21.0.0	Residual Oil[m]	1.2	9.4	20	2.8		3.3	5.3	59	500	53
3.1.21.1.0	Tangential Firing	0.0095	0.075	0.16	0.022		0.026	0.0053	0.47	5.0	0.43
3.1.21.0.2	All Other	1.2	9.3	20	2.8		3.3	5.3	58	500	53
3.1.22.0.0	Distillate Oil[n]	ND	1.3	ND				84	ND		ND
3.1.22.0.1	Tangential Firing	ND	0.013	ND				0.83	ND		ND
3.1.22.0.2	All Other	ND	1.3	ND				83	ND		ND
3.1.30.0.0	Gas[f]										
3.1.30.0.1	Tangential Firing										
3.1.30.0.2	All Other										
3.1.42.0.0	Wood/Bark[g]										

NOTE: See Volume II, Table 116 for explanation of footnotes.

Table 19 (continued). FLUE GAS EMISSIONS FROM COMMERCIAL/INSTITUTIONAL EXTERNAL COMBUSTION, 1973[a]

		Trace elements,[i] tons/yr									
		Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni	Se
3.0.00.0.0	Commercial	79	330	700	4,100	19	5.0	1.7	72	1,500	13.4
3.1.00.0.0	External Combustion	79	330	700	4,100	19	5.0	1.7	72	1,500	13.4
3.1.10.0.0	Coal[j]	13	20	700	4,100	9.5	45	1.1	4.5	18	9.1
3.1.11.0.0	Bituminous[k]	3.5	12	360	3,400	8.6	44	0.57	3.4	13	8.8
3.1.11.1.0	Pulverized Dry	2.7	9.4	59	2,600	6.6	34	0.11	2.6	10	1.7
3.1.11.2.0	Pulverized Wet	0.11	0.36	2.3	100	0.26	1.3	0.0057	0.10	0.42	0.092
3.1.11.4.0	All Stokers	0.66	2.3	100	660	1.7	8.6	0.46	0.66	2.6	7.0
3.1.12.0.0	Anthracite[l]	9.6	7.9	340	710	0.94	1.4	0.52	1.1	5.3	0.29
3.1.12.4.0	All Stokers	9.6	7.9	340	710	0.94	1.4	0.52	1.1	5.3	0.29
3.1.12.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0	0
3.1.13.0.0	Lignite	0	0	0	0	0	0	0	0	0	0
3.1.13.4.0	All Stokers	0	0	0	0	0	0	0	0	0	0
3.1.13.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0	0
3.1.20.0.0	Petroleum	66	310	0.12	220	1.2	4.7	0.61	67	1,500	4.3
3.1.21.0.0	Residual Oil[m]	66	310	0.12	220	1.2	4.7	0.61	67	1,500	4.3
3.1.21.1.0	Tangential Firing	0.52	2.5	0.0012	1.7	0.0095	0.037	0.0061	0.52	12	0.043
3.1.21.0.2	All Other	65	310	0.12	220	1.2	4.7	0.61	66	1,500	4.3
3.1.22.0.0	Distillate Oil[n]		0.66				0.17	ND		ND	ND
3.1.22.0.1	Tangential Firing		0.0065				0.0017	ND		ND	ND
3.1.22.0.2	All Other		0.65				0.17	ND		ND	ND
3.1.30.0.0	Gas[o]										
3.1.30.0.1	Tangential Firing										
3.1.30.0.2	All Other										
3.1.42.0.0	Wood/Bark[g]										

NOTE: See Volume II, Table 116 for explanation of footnotes.

Table 19 (continued). FLUE GAS EMISSIONS FROM COMMERCIAL/INSTITUTIONAL EXTERNAL COMBUSTION, 1973[a]

		Trace elements,[i] ton/yr							
		Te	Tl	Sn	Ti	U	V	Zn	Zr
3.0.00.0.0	Commercial	0.31	0.12	16	880	55	1,700	30	49
3.1.00.0.0	External Combustion	0.31	0.12	16	880	55	1,700	30	49
3.1.10.0.0	Coal[j]	0.31	0.12	1.0	620	14	26	24	49
3.1.11.0.0	Bituminous[k]	0.30	0.095	0.90	560	14	26	21	44
3.1.11.1.0	Pulverized Dry	0.23	0.073	0.70	430	11	20	16	34
3.1.11.2.0	Pulverized Wet	0.0091	0.0029	0.027	18	0.44	0.78	0.62	1.4
3.1.11.4.0	All Stokers	0.056	0.019	0.17	110	2.7	4.7	3.9	8.6
3.1.12.0.0	Anthracite[l]	0.011	0.011	0.11	63	0.29	1.4	3.1	5.0
3.1.12.4.0	All Stokers	0.011	0.011	0.11	63	0.29	1.4	3.1	5.0
3.1.12.6.0	Spreader Stokers	0	0	0	0	0	0	0	0
3.1.13.0.0	Lignite	0	0	0	0	0	0	0	0
3.1.13.4.0	All Stokers	0	0	0	0	0	0	0	0
3.1.13.6.0	Spreader Stokers	0	0	0	0	0	0	0	0
3.1.20.0.0	Petroleum			15	160	41	1,700	5.6	
3.1.21.0.0	Residual Oil[m]				160	41	1,700	5.6	
3.1.21.1.0	Tangential Firing				1.3	0.32	13	0.044	
3.1.21.0.2	All Other				160	41	1,700	5.6	
3.1.22.0.0	Distillate Oil[n]			15			ND	ND	
3.1.22.0.1	Tangential Firing			0.15			ND	ND	
3.1.22.0.2	All Other			15			ND	ND	
3.1.30.0.0	Gas[o]								
3.1.30.0.1	Tangential Firing								
3.1.30.0.2	All Other								
3.1.42.0.0	Wood/Bark[g]								

NOTE: See Volume II, Table 116 for explanation of footnotes.

SECTION V

RESIDENTIAL COMBUSTION SYSTEMS

Total fuel consumption by the residential sector is estimated to be $10,350 \times 10^{12}$ Btu/yr, with $8,057 \times 10^{12}$ Btu used for space heating. Estimates for the major fuel classifications are presented in Table 20. Residential fuel usage was based on apportionment of the available Bureau of Mines fuel use data for the combined commercial/residential sectors to the residential sector, by considering the number of dwellings in a state using each fuel, the average degree days within each state, and the appropriate fuel consumption factors per degree day.

Table 20. RESIDENTIAL FUEL USE, 1973

		Percent of total fuel used for space heating[a]	Fuel use: space heating 10^{12} Btu/yr
4.0.00.0.0	Residential		8,057
4.1.00.0.0	External Combustion	78	8,057
4.1.10.0.0	Coal	100	192
4.1.11.0.0	Bituminous	100	115
4.1.12.0.0	Anthracite	100	75
4.1.13.0.0	Lignite	100	2
4.1.20.0.0	Petroleum[b]	94	2,280
4.1.22.0.0	Distillate Oil	94	2,280
4.1.30.0.0	Gas	70	5,450
4.1.42.0.0	Wood	100	135

[a] Total fuel consumed in residential sector estimated to be $10,350 \times 10^{12}$ Btu/yr.

[b] Over 95 percent No. 1 or No. 2 distillate oil.

Nationwide emission estimates for residential combustion systems are presented in Table 21. Although residential units are a minor source of criteria pollutant and trace element emissions, they are, on the basis of the available data, the principal combustion source of polycyclic organic matter emissions. Coal combustion appears to be the major contributor to POM emissions despite the small amount of coal burned. It has also been hypothesized that residual oil combustion contributes significantly to high sulfuric acid levels in many eastern urban areas.[9]

Table 21. FLUE GAS EMISSIONS FROM RESIDENTIAL COMBUSTION, 1973[a]

		Particulates, 10^3 tons/yr		Gases, 10^3 tons/yr				Organics,[i] tons/yr		
		Total	<3μ[g]	SO_x	NO_x	HC	CO	BSO	PPOM	BaP
4.0.00.0.0	Residential	230	120	1,400	350	110	470	69,000	4,100	390
4.1.00.0.0	External Combustion	230	120	1,400	350	110	470	69,000	4,100	390
4.1.10.0.0	Coal	69	1.3	240	12	57	370	43,000	4,000	380
4.1.11.0.0	Bituminous[b,c]	53	1.0	210	7.9	53	240	26,000	2,400	230
4.1.12.0.0	Anthracite[b,d]	15	0.29	27	4.3	3.6	130	17,000	1,600	150
4.1.13.0.0	Lignite[e]	1.4	0.027	1.0	0.3	0.05	0.1	450	42	3.6
4.1.20.0.0	Petroleum	82	74	1,200	98	25	41	14,000	11	1.1
4.1.22.0.0	Distillate Oil[f]	82	74	1,200	98	25	41	14,000	5.2	0.50
4.1.30.0.0	Gas[g]	52	47	1.5	210	21	54	12,000	6.3	0.60
4.1.42.0.0	Wood/Bark[h]	25	0.49	3.7	25	5.0	5.0	840	77	7.4

NOTE: See Volume II, Table 126 for explanation of footnotes.

Table 21 (continued). FLUE GAS EMISSIONS FROM RESIDENTIAL COMBUSTION, 1973[a]

		Trace elements,[j] tons/yr									
		Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
4.0.00.0.0	Residential	0.031	1.9	3.2	0.16	0.053	2.7	83	0.021	12,000	2.4
4.1.00.0.0	External Combustion	0.031	1.9	3.2	0.16	0.053	2.7	83	0.021	12,000	2.4
4.1.10.0.0	Coal[k]	0.031	1.8	3.2	0.16	0.053	2.7	81	0.021	12,000	2.4
4.1.11.0.0	Bituminous[l]	0.03	1.6	1.9	0.12	0.05	2.6	78	0.020	7,800	0.7
4.1.12.0.0	Anthracite[m]	0.001	0.15	0.89	0.04	0.001	0.015	2.9	0.0010	4,400	1.7
4.1.13.0.0	Lignite[n]			0.42		0.002	0.057			16	0.006
4.1.20.0.0	Petroleum	ND	0.05	ND				2.0	ND		ND
4.1.22.0.0	Distillate Oil[o]	ND	0.05	ND				2.0	ND		ND
4.1.30.0.0	Gas[p]										
4.1.42.0.0	Wood/Bark										

NOTE: See Volume II, Table 126 for explanation of footnotes.

Table 21 (continued). FLUE GAS EMISSIONS FROM RESIDENTIAL COMBUSTION, 1973[a]

		Trace elements,[j] tons/yr									
		Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni	Se
4.0.00.0.0	Residential	1 5	1.9	740	280	0.64	26	1.4	0.35	1.5	10
4.1.00.0.0	External Combustion	1.5	1.9	740	280	0.64	26	1.4	0.35	1.5	10
4.1.10.0.0	Coal[k]	1.5	1.8	740	280	0.64	26	1.4	0.35	1.5	10
4.1.11.0.0	Bituminous[l]	0.20	0.7	420	180	0.5	23	0.65	0.2	0.8	10
4.1.12.0.0	Anthracite[m]	1.3	1.1	320	99	0.13	2.6	0.78	0.15	0.73	0.4
4.1.13.0.0	Lignite[n]	0.005	0.008			0.009	0.039	0.002	0.004		
4.1.20.0.0	Petroleum		0.05				0.006	ND		ND	ND
4.1.22.0.0	Distillate Oil[o]		0.05				0.006	ND		ND	ND
4.1.30.0.0	Gas[p]										
4.1.42.0.0	Wood/Bark										

NOTE: See Volume II, Table 126 for explanation of footnotes.

Table 21 (continued). FLUE GAS EMISSIONS FROM RESIDENTIAL COMBUSTION, 1973[a]

		Trace elements,[j] tons/yr							
		Te	Tl	Sn	Ti	U	V	Zn	Zr
4.0.00.0.0	Residential	0.021	0.006	0.18	40	0.8	1.6	3.1	3.8
4.1.00.0.0	External Combustion	0.021	0.006	0.18	40	0.8	1.6	3.1	3.8
4.1.10.0.0	Coal[k]	0.021	0.006	0.064	40	0.8	1.6	3.1	3.8
4.1.11.0.0	Bituminous[l]	0.020	0.005	0.05	31	0.8	1.4	1.1	2.4
4.1.12.0.0	Anthracite[m]	0.001	0.001	0.01	8.7	0.004	0.19	2.0	1.4
4.1.13.0.0	Lignite[n]			0.004			0.012	0.018	
4.1.20.0.0	Petroleum			0.12			ND	ND	
4.1.22.0.0	Distillate Oil[o]			0.12			ND	ND	
4.1.30.0.0	Gas[p]								
4.1.42.0.0	Wood/Bark								

NOTE: See Volume II, Table 126 for explanation of footnotes.

SECTION VI

TRENDS IN FUEL CONSUMPTION AND COMBUSTION SYSTEM DESIGN

FUEL CONSUMPTION

The prediction of fossil fuel consumption patterns over the next decade is dependent upon political, economic, environmental, and technological considerations. Federal regulations and pricing policies will play a major role in determining future fuel use patterns and boiler design parameters. The trends presented in Volume II of this report are largely based on the Project Independence Report published in November, 1974.[10] Estimates of fuel consumption trends from stationary combustion systems are given in Table 22 for the major fuels. Coal consumption is predicted to increase sharply, with oil decreasing in overall usage and gas undergoing a modest increase.

In the electric utility sector the use of coal is predicted to double while the use of oil and gas will decline. Specifically the use of bituminous, subbituminous and lignite will increase sharply whereas anthracite consumption will decline. Western coal consumption will increase faster than eastern coal and will increase from 11.6 percent of coal consumed in 1974 to about 20 percent in 1985. The major effect of the trend to western coal will be a reduction in the potential SO_2 emissions per unit of fuel. Further the use of western coal will significantly affect the design and application of boilers and control methods.

Coal and oil consumption by the industrial sector will increase 40 to 45 percent each and gas consumption will remain essentially constant. The

Table 22. FUEL CONSUMPTION TRENDS, STATIONARY COMBUSTION SOURCES[a]

	1973[b] fuel 10^{12} Btu	1985 fuel 10^{12} Btu	Percent change 1973[b]–1985
Total	38,701[c,d,g]	49,843[e,f,g]	+29
Coal	10,220	19,095	+87
Oil	9,958	9,801	-2
Gas	18,523	20,947	+13
Electric utilities	15,387	22,531[e]	+46
Coal	8,502	16,994	+100
Oil	3,351	3,016	-10
Gas	3,534	2,485	-30
Industrial	11,300[c]	12,934[f]	+14
Coal	1,370	1,945	+42
Oil	2,060	2,966	+44
Gas	7,600	7,600	+0
Commercial/Institutional	4,500[d]	4,941	+10
Coal	156	70	-55
Oil	2,404	2,019	-16
Gas	1,939	2,851	+47
Residential	8,057[g]	9,258[g]	+15
Coal	192	86	-55
Oil	2,143	1,800	-16
Gas	5,450	8,011	+47

[a]Electric generation process steam, space heating, and stationary engines.

[b]Utility data represents 1974

[c]Includes 250 x 10^{12} Btu wood and 20 x 10^{12} Btu bagasse

[d]Includes 1 x 10^{12} Btu wood.

[e]Includes 36 x 10^{12} Btu refuse

[f]Includes 400 x 10^{12} Btu wood and 23 x 10^{12} Btu bagasse

[g]Includes 135 x 10^{12} Btu wood

increase in coal consumption will increase the need for control equipment in the industrial sector.

Fuel consumption trends for the commercial/institutional and residential sectors were assumed to be identical. The major trend for these sectors is a large increase in the use of natural gas. Coal is only a minor fuel for these sectors and its use will continue to decline.

COMBUSTION SYSTEMS

The trends to 1985 for combustion system types within each combustion sector were estimated. Table 23 presents the detailed trend estimates for the electric utility sector. Significant among the trends in the electric utility sector is the lack of growth predicted for cyclone-fired boilers due to their high NO_x emission levels, which generally exceed New Source Performance Standards. In addition the use of gas turbines will increase sharply. Detailed boiler age data presented in Volume II indicates a trend to larger boilers and to opposed firing units. Tangentially-fired units may also be widely used since NO_x emissions are more easily controlled in this unit type. Regulations will be of major significance in the modification of boiler design and operating procedures. Practically all electric utilities and industrial plants will be subject to Federal and State air, water and solid waste regulations.

Table 23. ELECTRIC UTILITY FUEL CONSUMPTION TRENDS TO 1985 BY COMBUSTION SYSTEM TYPE

		1974 10^{12} Btu	1985 10^{12} Btu	Percent change 1974-1985
1.0.00.0.0	Electric Generation	15,387	22,531	+ 46
1.1.00.0.0	External Combustion	14,798	20,932	+ 42
1.1.10.0.0	Coal	8,502	16,994	+100
1.1.11.0.0	Bituminous	8,264	14,976	+ 81
1.1.11.1.0	Pulverized Dry	5,971	11,877	+ 99
1.1.11.2.0	Pulverized Wet	1,118	1,952	+ 75
1.1.11.3.0	Cyclone	1,118	1,118	+ 0
1.1.11.4.0	All Stokers	57	29	- 50
1.1.12.0.0	Anthracite	38	19	- 50
1.1.12.1.0	Pulverized Dry	13	9	- 30
1.1.12.2.0	Pulverized Wet	0	0	0
1.1.12.3.0	Cyclone	0	0	0
1.1.12.4.0	All Stokers	25	10	- 60
1.1.13.0.0	Lignite	200	2,000	+1000
1.1.13.1.0	Pulverized Dry	120	1,730	+1400
1.1.13.2.0	Pulverized Wet	30	220	+ 730
1.1.13.3.0	Cyclone	30	30	+ 0
1.1.13.4.0	All Stokers	20	20	0
1.1.20.0.0	Oil	3,039	2,172	- 29
1.1.21.0.0	Residual Oil	2,901	2,060	- 29
1.1.21.0.1	Tangential Firing	1,128	801	- 29
1.1.21.0.2	All Other	1,773	1,259	- 29
1.1.22.0.0	Distillate Oil	138	99	- 29
1.1.22.0.1	Tangential Firing	54	38	- 29
1.1.22.0.2	All Other	84	61	- 29
1.1.30.0.0	Gas	3,257	1,780	- 55
1.1.30.0.1	Tangential Firing	791	356	- 55
1.1.30.0.2	All Other	2,466	1,344	- 55
1.1.40.1.1	Refuse	0.6	36	+6000
1.2.00.0.0	Internal Combustion	589	1,549	+262
1.3.00.0.0	Turbine	515	1,467	+285
1.3.20.0.0	Oil	286	815	+285
1.3.30.0.0	Gas	229	652	+285
1.4.00.0.0	Reciprocating	74	82	+ 10
1.4.20.0.0	Oil	26	29	+ 10
1.4.30.0.0	Gas	48	53	+ 10

SECTION VII

ON-GOING AND PLANNED RESEARCH ACTIVITIES

A listing of current and planned investigations into pollutant emissions from conventional stationary combustion sources is presented in Volume II. Those projects which are identified include, when possible, the project title and Contract Number, supporting and performing organization, principal investigator, a brief project description, and the planned completion date. The program discussions are presented according to the major unit operations contributing to pollutant emissions.

The following summary briefly identifies the major trends in research and development investigations of emissions and the environmental impacts of conventional combustion systems operation:

- Combustion - Studies are principally concerned with the design of new units, boilers or internal combustion engines, or modification of existing units in order to improve combustion efficiency, lower pollutant levels, or allow the burning of different fuels. NO_x reduction measures and improvement of the combustion efficiency of small burners are receiving attention.

- Flue Gas Emissions

  - Particulate - The trend is toward the investigation of fine particulate distributions and compositions using cascade impactors and condensation nuclei counters in order to determine fine particulate distributions and control efficiencies. Fine particulates are of concern because of the health effects associated with respirable particulates. Emphasis is also being placed on secondary reactions which occur in the plume after exit from the stack with major interest pertaining to the formation of sulfate, nitrate, and POM bearing particulates.

- Other Criteria Pollutants - Since a large portion of sulfur in fuel is emitted as SO_x through the stack, research has centered upon eliminating sulfur prior to combustion or removing it from the flue gas after combustion. The atmospheric sulfur cycle and SO_3 and sulfuric acid measurement techniques are also being studied.

  NO_x emission reduction programs include analysis of fuel conversion alternatives, boiler modification, variation in operating parameters, catalytic stack gas removal, flue gas scrubbing and alternatives to water injection (for stationary engines).

  Stationary combustion is a minor source of HC and CO and has been researched accordingly.

- POM - Investigations include assessment of sampling procedures, analysis of POM compounds, and measurement of total emissions of POM from stationary sources.

- Trace Elements - Fine particulate trace elements present a potential health hazard due to their respirable nature. The trend toward increased use of coal has emphasized the need to investigate trace element emissions, control methods, and hazardous plume and atmospheric transformations.

- Ash Handling - Studies pertain to identification of bottom ash and fly ash distribution and composition, and ash reutilization. Investigations into ash pond discharge, potential leachates from landfill, fixation processes, and the use and durability of pond liners are being conducted. Analysis of soil migration rates, hazardous effects to soil receptors, and interactions of metals and organics are on-going or planned.

- Cooling Systems - Current projects are investigating the reduction of water consumption, elimination of salt drift, and the reduction of thermal pollution and chemical contamination of surface waters. The majority of these studies involve dry and wet/dry cooling systems as a means to that end.

- Water Recycle/Reuse - Current studies are underway to identify design and cost information on methods of reducing water consumption and wastewater discharges through water recycle/reuse and treatment. These studies are assessing the potential for cascading water use and treatment of the major plant wastewater streams.

- Boiler Water Treatment - Investigations are being made into current boiler operating standards in order to establish the state-of-the-art and recommend required alterations. The major problem areas are turbine damage and control of corrosion and scale deposition in steam generator tubing.

- Fuels and Fuel Handling - A number of investigations are on-going or planned to characterize air emissions and acid drainage from coal storage piles. Cleaning of coal prior to combustion is another area of study.

- Flue Gas Desulfurization - The current research concerns removal of SO_x from flue gases by many processes in all stages of development. Sludge disposal methods are under active investigation.

- Control Devices - A variety of studies are being performed to determine the particulate control efficiency of electrostatic precipitators, wet scrubbers, fabric filters, and novel control devices. Attention is being given to the effect of fuel and boiler type on control efficiencies of fine particulates. Filters and scrubbers merit further study; scrubbers are of interest because of their potential for reduction of vapor phase emissions.

SECTION VIII

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APPENDIX A

METRIC CONVERSIONS

A. CAPACITY, ENERGY, FORCE, HEAT

Multiply	By	To obtain
Btu	0.2520	Kilogram-calories
Btu/min	3.927×10^{-4}	Horsepower-hrs
Btu/min	2.928×10^{-4}	Kilowatt-hrs
Btu/min	0.02356	Horsepower
Btu/min	0.01757	Kilowatts
Btu/min	10^{-3}	Pound/hr steam
Horsepower (boiler)	33,479	Btu/hr
Horsepower (boiler)	9.803	Kilowatts
Horsepower-hours	0.7457	Kilowatt-hours
Kilowatts	56.92	Btu/min
Kilowatts	1.341	Horsepower
Kilowatt-hours	3415	Btu
Kilowatt-hours	1.341	Horsepower-hrs
Megawatts	1360	Kilograms/hr steam
Pound/hr steam	0.454	Kg/hr

Energy equivalences of various fuels:

Bituminous coal - 22.4×10^6 Btu/ton, 1971-1973
21.9×10^6 Btu/ton, 1974

Anthracite coal - 26.0×10^6 Btu/ton

Lignite coal - 16.0×10^6 Btu/ton

Residual oil - 147,000 Btu/gal

Distillate oil - 140,000 Btu/gal

Natural gas - 1,022 Btu/ft^3

1 lb of water evaporated from and at 212°F equals:

0.2844 Kilowatt-hours
0.3814 Horsepower-hours
970.2 Btu

B. FLOW

Multiply	By	To obtain
Cubic feet/minute	0.1247	Gallons/sec.
Cubic feet/second	0.646317	Million gals/day
Cubic feet/second	448.831	Gallons/min
Cubic meter/sec.	22.8	Million gals/day
Cubic meter/sec.	8.32×10^{9}	Gallons/year
Gallons/year	10.37×10^{-6}	m^3/day
Gallons/min.	2.228×10^{-3}	Cubic feet/sec.
Liters/min.	5.886×10^{-4}	Cubic ft/sec,
Liters/min.	4.403×10^{-3}	Gals/sec.
Million gals/day	1.54723	Cubic ft/sec.
Million gals/day	0.044	Cubic meters/sec.
Million gals/day	695	Gallons/min.
Pounds of water/min.	2.679×10^{-4}	Cubic ft/sec.

C. LENGTH, AREA, VOLUME

Multiply	By	To obtain
Acres	43,560	Square feet
Acres	4047	Square meters
Acres	1.562×10^{-3}	Square miles
Acre-feet	43,560	Cubic feet
Acre-feet	325,851	Gallons
Acre-feet	1233.49	Cubic meters
Barrels-oil	0.156	Cubic meters
Barrels-oil	42	Gallons-oil
Centimeters	0.3937	Inches
Cubic feet	2.832×10^{4}	Cubic cms.
Cubic feet	1728	Cubic inches
Cubic feet	0.02832	Cubic meters
Cubic feet	0.03704	Cubic yards
Cubic feet	7.48052	Gallons
Cubic feet	28.32	Liters
Cubic meters	35.31	Cubic feet
Cubic meters	264.2	Gallons
Feet	30.48	Centimeters
Feet	0.3048	Meters

Gallons	0.1337	Cubic feet
Gallons	3.785×10^{-3}	Cubic meters
Gallons, Imperial	1.20095	U.S. gallons
Gallons water	8.3453	Pounds of water
Liters	0.2642	Gallons
Meters	3.281	Feet
Meters	39.37	Inches
Square feet	2.296×10^{-5}	Acres
Square feet	0.09290	Square meters
Square meters	2.471×10^{-4}	Acres
Square meters	10.76	Square feet
Square miles	640	Acres

D. MASS, PRESSURE, TEMPERATURE, CONCENTRATION

Multiply	By	To obtain
Atmospheres	29.92	Inches of mercury
Atmospheres	33.90	Feet of water
Atmospheres	14.70	Lbs/sq. inch
Grams	15.43	Grains (troy)
Grams/liter	58.417	Grains/gal
Grams/liter	8.345	Pounds/1000 gals.
Grams/liter	0.062427	Pounds/cubic ft
Kilograms	2.2046	Pounds
Parts/million	0.0584	Grains/U.S. gal
Parts/million	8.345	Lbs/million gal
Pounds	453.5924	Grams
Pounds of water	0.01602	Cubic feet
Pounds of water	0.1198	Gallons
Pounds/sq. inch	0.06804	Atmospheres
Pounds/sq. inch	2.307	Feet of water
Pounds/sq. inch	2.036	Inches of mercury
Temp. (^{o}C) + 32	1.8	Temp. (^{o}F.)
Temp. (^{o}F) - 32	0.555	Temp. (^{o}C.)
Tons (metric)	2205	Pounds
Tons (short)	2000	Pounds
Tons (short)	0.89287	Tons (long)
Tons (short)	0.9975	Tons (metric)

APPENDIX B

ACRONYMS USED IN THIS REPORT

BaP	Benzo(a)pyrene
BSO	Benzene Soluble Organics
Btu	British Thermal Units
EPA	Environmental Protection Agency
FGD	Flue Gas Desulfurization
FPC	Federal Power Commission
kWh	Kilowatt Hours
MW	Megawatts
MWh	Megawatt Hours
NPDES	National Pollution Discharge Elimination System
NEDS	National Emission Data System
PBB	Polybrominated Biphenyls
PCB	Polychlorinated Biphenyls
PHH	Polyhalogenated Hydrocarbons
POM	Polycyclic Organic Matter
SOTDAT	Source Test Data System
TS	Total Solids
TDS	Total Dissolved Solids
TSS	Total Suspended Solids
TLV	Threshold Limit Value